S. HRG. 112–901

NATURAL GAS DRILLING: PUBLIC HEALTH AND ENVIRONMENTAL IMPACTS

JOINT HEARING

BEFORE THE

SUBCOMMITTEE ON WATER AND WILDLIFE

AND THE

COMMITTEE ON ENVIRONMENT AND PUBLIC WORKS UNITED STATES SENATE

ONE HUNDRED TWELFTH CONGRESS

FIRST SESSION

APRIL 12, 2011

Printed for the use of the Senate Committee on Environment and Public Works

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ONE HUNDRED TWELFTH CONGRESS
FIRST SESSION

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NATURAL GAS DRILLING: PUBLIC HEALTH AND ENVIRONMENTAL IMPACTS

TUESDAY, APRIL 12, 2011

U.S. SENATE,
COMMITTEE ON ENVIRONMENT AND PUBLIC WORKS,
JOINTLY WITH THE
SUBCOMMITTEE ON WATER AND WILDLIFE,
Washington, DC.

The committee and subcommittee met, pursuant to notice, at 9:15 a.m. in room 406, Dirksen Senate Office Building, Hon. Benjamin L. Cardin, (chairman of the subcommittee) presiding.

Present: Senators Cardin, Boxer, Inhofe, Sessions, Lautenberg, Whitehouse, Barrasso, Udall, Merkley and Boozman.

STATEMENT OF HON. BENJAMIN L. CARDIN, U.S. SENATOR FROM THE STATE OF MARYLAND

Senator CARDIN. Good morning everyone. Welcome to the joint hearing between the full Environment and Public Works Committee and the Subcommittee on Water and Wildlife. I want to thank Senator Boxer and Senator Inhofe for arranging for this hearing. I want to thank my colleagues that are here that are prepared to testify.

Let me start by saying the United States has as much natural gas as Saudi Arabia has oil. According to Penn State, the Marcellus Shale which runs from Central New York State to West Virginia may be the second largest natural gas field in the world. We have enormous reserves that can help America meet its energy needs and do so in a way that produces far less pollution than coal, help the United States on its path to energy independence, and improve our national security.

High volume horizontal hydraulic fracturing, or fracking, is now being used to extract natural gas from shale formations in thousands of new wells. In Pennsylvania, more than 2,700 Marcellus wells were drilled from 2006 to March 10 of this year. A study last year estimated that Marcellus drilling would create or support more than 100,000 jobs in 2011 plus billions of dollars in economic value for the State.

The natural gas industry is booming, but it may be in jeopardy. New York has imposed a moratorium on fracking operations. New Jersey is considering a ban on the practice. The city of Pittsburgh has enacted a ban on fracking operations within the city limits. Tiny Mountain Lake Park, MD adopted an ordinance making the drilling of natural gas illegal within the town limits.

So why is this happening? The answer is simple. The industry has failed to meet minimal acceptable performance levels for protecting human health and the environment. That is both an industry failure and a failure of the regulatory process.

I am a strong supporter of domestic natural gas production, but my support only comes when human health and the environment are protected. The record is replete with cases of contamination from improper cement job, cracked drilling casing, drill pad spills and disturbances releasing natural gas in higher geological formations.

In June 2010, the Pennsylvania Land Trust Association identified a total of 1,614 violations occurred by 45 Pennsylvania Marcellus Shale drillers dating to January 2008, including 91 violations of Pennsylvania's clean stream laws, 162 cases of improper construction of wastewater impoundments, 50 cases of improper well casing construction, and four cases of inadequate blowout prevention. Last June, a well blowout in Clearfield County shot 35,000 gallons of gas and water 75 feet in the air over a 16-hour period.

Municipal wastewater treatment plants are not equipped to handle the contaminants that come out of the fracking operations. Five million gallons of water, combined with thousands of gallons of special chemicals, can be used in a single fracking operation. Much of this is returned to the surface. Then it is either injected into underground wells or it is used by wastewater treatment facility plants, and the wastewater treatment plants cannot handle that type of pollutant.

The question is: What is EPA doing about this? We understand that fracking is exempt from certain parts of the Clean Water Act, but it is certainly subject to the provisions that deal with wastewater treatment. Is EPA acting on these areas? That is one of the areas I hope that this hearing will deal with.

The challenge is that State regulators have not been able to handle the issue. We are exempt from several of the Federal laws. However, it is subject to other provisions within the Clean Water Act and whether we have an adequate regulatory system that protects the public so that we can get the natural gas that is critically important to our country.

It is my hope that this hearing will help answer these questions. I thank the witnesses that are here today. I thank our two colleagues who are participating in this hearing. We need to get this right. We need to figure out how we can get the natural gas that is plentiful in the United States in an environmentally safe way.

We have allowed for State regulation, but in some cases State regulation has been inadequate. We do have Federal laws, some apply, some are exempt, and the question is whether we are in fact adhering to the Federal environmental rules that are currently in existence.

What do we do with the wastewater? How do we treat it? How do we deal with the danger to our environment? I hope this hearing will help us in that pursuit.

[The prepared statement of Senator Cardin follows:]

STATEMENT OF HON. BENJAMIN L. CARDIN, U.S. SENATOR FROM THE STATE OF MARYLAND

The United States has as much natural gas as Saudi Arabia has oil. According to Penn State, the Marcellus Shale, which runs from central New York State to West Virginia, may be the second largest natural gas field in the world.

We have enormous reserves that can help America meet its energy needs and do so in a way that produces far less pollution than coal, helps the United States on its path to energy independence, and improves national security.

High volume, horizontal hydraulic fracturing, or "fracking," is now being used to extract natural gas from shale formations in thousands of new wells. In Pennsylvania more than 2,700 Marcellus wells were drilled from 2006 to March 10th of this year.

A study last year estimated that Marcellus drilling would create or support more than 100,000 jobs in 2011, plus billions of dollars in economic value for the state.

The natural gas industry is booming, but that may soon end. Against the backdrop of natural gas's promise,

- New York has imposed a moratorium on fracking operations.
- New Jersey is considering a ban on the practice.
- The city of Pittsburgh has enacted a ban on fracking operations within the city limits.
- Tiny Mountain Lake Park, Maryland adopted an ordinance making the drilling of natural gas illegal within the town limits.

What's going on? In the face of its extraordinary promise, why is natural gas faltering?

The answer is simple. The industry has failed to meet minimally acceptable performance levels for protecting human health and the environment. That is both an industry failure and a failure of the regulatory agencies.

I am a strong supporter of domestic natural gas production. But my support only comes when human health and the environment are protected.

POTENTIAL HUMAN HEALTH AND ENVIRONMENTAL IMPACTS

The natural gas industry argues that there has never been a documented case of drinking water contamination from fracking.

Viewed in isolation, fracking occurs far below drinking water aquifers. But fracking doesn't mysteriously just happen. It involves drilling, wells, water, compressors, and all the associated equipment that goes into a modern well-drilling operation.

The record is replete with cases of contamination from improper cement jobs, cracked drill casings, drill pad spills, and seismic disturbances releasing natural gas in higher geological formations. For example, Pennsylvania DEP brought an enforcement action against Cabot Oil for poor cementing after the drinking water wells of 19 families in Dimock, PA were polluted.

In June 2010, the Pennsylvania Land Trust Association identified a total of 1614 violations accrued by 45 Pennsylvania Marcellus Shale drillers, dating to January 2008, including:

- 91 violations of Pennsylvania's Clean Streams Law
- 162 cases of Improper Construction of Waste Water Impoundments
- 50 cases of Improper Well-Casing Construction, and
- 4 cases of inadequate Blowout Prevention. Last June a well blowout in Clearfield County shot 35,000 gallons of gas and water 75 ft. into the air over a 16 hour period.

Pro Publica, the investigative news site, has found over 1,000 reports of water contamination near drilling sites.

Up to 5 million gallons of water combined with thousands of gallons of special chemicals can be used in a single fracking operation, much of this returning to the surface.

This flowback fluid contains not only the chemicals used in the fracking process, but can also include salts, metals, and naturally occurring radioactive substances.

Municipal wastewater treatment plants are not equipped to handle these contaminants. In Pennsylvania, more than a dozen publically owned treatment works facilities accepting natural gas wastewater have failed to treat it in accordance with permit requirements. Radioactive isotopes, heavy salts, and other chemicals were discharged into surface waters—all in apparent violation of the Clean Water Act.

Even specialized facilities can have problems.

Studies of the effluent from a commercial facility in Pennsylvania that collects water only from gas operations show half a dozen pollutants in excess of their approved limits as determined by an agency at the Centers for Disease Control.

The contaminants include:

- Chloride, which has been found at levels that are hundreds of times higher than accepted health levels.
- Benzene, a known carcinogen, has been detected at levels thousands of times above health limits.
- Bromide reacts with other chemicals to form potentially carcinogenic compounds. It is present at levels tens of thousands of times higher than the levels of concern.

Under the Safe Drinking Water Act, the EPA would typically be allowed to regulate all underground injections of fluids, including the chemicals used in fracking, cement jobs, casings, and disposal of flowback water. However, a loophole exempts fracking from regulation, except where diesel fuel is used.

Even with this huge loophole, Federal violations have occurred. Since 2005, companies have injected over 32 million gallons of diesel fuel or fracking fluids containing diesel fuel in wells in 19 states. None of these operations obtained a permit under the Safe Drinking Water Act, meaning that all are in violation. To date, EPA has failed to take any enforcement action.

Similar restrictions on the Clean Water Act allow drilling companies to operate outside its scope.

State regulators, facing their own massive budget cuts, have tried to fill the void. In the Marcellus Shale area, Pennsylvania's response has been characterized as playing continual regulatory catch-up, as regulations have routinely failed to address issues.

As today's hearing will make clear, the exemptions from the Safe Drinking Water Act and Clean Water Act aren't working.

We need to put the environmental cop back on the beat, take aggressive action against the bad actors in the industry and earn back the public's confidence.

The promise of natural gas will be a promise unfulfilled if the human health and environmental impacts are not properly safe-guarded. It's long past time that they were.

With that, let me turn to the Ranking Republican Member of the full committee, Senator Inhofe.

STATEMENT OF HON. JAMES M. INHOFE, U.S. SENATOR FROM THE STATE OF OKLAHOMA

Thank you, Mr. Chairman.

I am really glad we are having this hearing because you hear this stuff about what a lousy job the States are doing, when in fact they are doing a great job. I have to say that on March 17 of 1949, more than 60 years ago, the first hydraulic fracturing job was performed in a well 12 miles east of Duncan in my home State of Oklahoma.

The practice has now been used on more than 1 million currently producing wells, 35,000 wells a year, without one confirmed case of groundwater contamination. But don't take my word for it. Let's hear what the experts, the State regulators, have said.

Nick Tew, Alabama State geologist, said: "There have been no documented cases of drinking water contamination that have resulted from hydraulic fracturing operations to stimulate oil and gas wells in the State of Alabama."

Cathy Foerster, Commissioner of the Alaskan Oil and Gas Conservation Commission: "There have been no verified cases of harm to groundwater in the State of Alaska as a result of hydraulic fracturing."

Harold Fitch, director, Michigan Office of Geological Survey at the Department of Environmental Quality: "There is no indication that hydraulic fracturing has ever caused damage to the groundwater or other resources in Michigan. In fact, the OGS has never received a complaint or allegation that hydraulic fracturing has impacted groundwater in any way."

Victor Carrillo, chairman of the Railroad Commission of Texas, that's the organization in Texas that has that jurisdiction, I might add: "Though hydraulic fracturing has been used for over 60 years in Texas, our Railroad Commission records do not reflect a single documented surface or groundwater contamination case."

Same thing is true with Fred Steece from South Dakota and all of these others. So I have these other statements I will include in the record.

[The referenced documents follow on page 255.]

Senator INHOFE. Now, let me show you why this is the case. We have a chart. Pull the chart up here. It is very important. Let it spread out and hold that up high enough that people can see it, if you would. Very good.

Now, the chart illustrates a cross-section of a typical well drilled in the Marcellus Shale in Southwest Pennsylvania. You see the blue line way up at the top, that little narrow blue line. That illustrates the groundwater aquifer. In between that groundwater aquifer and the Marcellus Shale are dozens of layers of solid rock, almost 2 miles of solid rock. Let me repeat that: 2 miles of solid rock between the aquifer and down here where they have the Marcellus Shale that is so valuable to the future of this country.

Now, see the small box at the top? That is a picture of the Empire State Building. I am trying to get this in perspective so that people can see that this stuff they hear just flat isn't true. For groundwater contamination to occur, frack fluids would have to migrate through 7,000 feet of solid rock. Once again, that is about the same as the distance from the west front of the Capitol all the way to the Washington Monument. The fluid migration can't happen and it doesn't happen.

Given these facts, what can possibly explain calls to regulate fracking from Washington, DC? It is simple. The Obama administration wants to regulate fossil fuels out of existence. Energy Secretary Steven Chu actually said, "Somehow we have to figure out how to boost the price of gasoline to the levels in Europe." For my colleagues who might not know, the price there is about $8 a gallon.

Or consider Alan Krueger of the Treasury Department in the Obama administration who said: "The Administration believes that it is no longer sufficient to address our Nation's energy needs by finding more fossil fuel."

That is what this is all about. Mr. Krueger's belief is now a reality. Gas at the pump is approaching $4 and we think it is going to be going on up.

Now, if you think these data points are bad, they will grow far worse under EPA's cap-and-trade agenda. As part of that agenda, the Agency is maneuvering to regulate hydraulic fracturing, a practice that has always been regulated by the States. Testimony today will confirm that States don't need the EPA. There is this mentality we have here in Washington, I would say to my friends, and I want to welcome Jeff Cloud from my State of Oklahoma, who is here to testify. It is the Corporation Commission, I would say to Senator Cornyn, in Oklahoma, not the Railroad Commission that regulates it in Oklahoma.

These people have been doing a good job, but the mentality that we have here in Washington is that nothing is done right unless it is done in Washington.

So the Nation's immense shale deposits are predominantly located in States that effectively and efficiently regulate oil and gas, in States such as Pennsylvania, Arkansas, Oklahoma, Texas, Louisiana, West Virginia, Ohio, and North Dakota. A virtual boom in natural gas development is transforming America's energy security due in no small measure to the absence of Federal regulation.

For this reason, I would only say that I agree with something that was said by the Chairman this morning when he was talking about the tremendous reserves. Our recoverable reserves in gas, and we were talking about natural gas this morning, are greater than any country in the world. We could run this country for 90 years on natural gas without importing any from the Middle East.

That is why this is important. For those people who say they want to cut down our dependence on the Middle East and at the same time kill natural gas production. Kill it? Yes, you start regulating. You can't get natural gas from these deposits without hydraulic fracturing. It has worked. It has been successful. We have to keep that for America.

Thank you.

[The prepared statement of Senator Inhofe follows:]

STATEMENT OF HON. JAMES M. INHOFE, U.S. SENATOR FROM THE STATE OF OKLAHOMA

On March 17, 1949, more than 60 years ago, the first hydraulic fracturing job was performed on a well 12 miles east of Duncan, in my home State of Oklahoma. The practice has now been used on more than 1 million currently producing wells, 35,000 wells per year, without one confirmed case of groundwater contamination from these fracked formations. But don't take my word for it. Let's hear what the experts, the State regulators, have said:

Nick Tew, Alabama State Geologist & Oil and Gas Supervisor.—"There have been no documented cases of drinking water contamination that have resulted from hydraulic fracturing operations to stimulate oil and gas wells in the State of Alabama."

Cathy Foerster, Commissioner of Alaska Oil and Gas Conservation Commission.—"There have been no verified cases of harm to groundwater in the State of Alaska as a result of hydraulic fracturing."

Harold Fitch Director, Michigan Office of Geological Survey of the Department of Environmental Quality.—"There is no indication that hydraulic fracturing has ever caused damage to groundwater or other resources in Michigan. In fact, the OGS has never received a complaint or allegation that hydraulic fracturing has impacted groundwater in any way."

Victor Carrillo, Chairman Railroad Commission of Texas.—"Though hydraulic fracturing has been used for over 60 years in Texas, our Railroad Commission records do not reflect a single documented surface or groundwater contamination case associated with hydraulic fracturing."

Fred Steece, Oil and Gas Supervisor of the South Dakota Department of Environment and Natural Resources.—"In the 41 years that I have supervised oil and gas exploration, production and development in South Dakota, no documented case of water well or aquifer damage by the fracking of oil or gas wells, has been brought to my attention. Nor am I aware of any such cases before my time."

And I have statements from eight more oil and gas producing states that I would like to submit for the record. They all state that hydraulic fracturing does not contaminate groundwater.

Now let me show you why this is the case. This chart illustrates a cross section of a typical well drilled in the Marcellus shale in southwest Pennsylvania. Do you see the small blue line at the top of the chart? That illustrates the groundwater aquifer. In between that groundwater aquifer and the Marcellus shale are dozens of layers of solid rock—more than a mile of it. Let me say that again: there is more than a mile that separates the groundwater aquifer and the well.

See the small blue box at the top? That's a picture of the Empire State Building. For groundwater contamination to occur, frack fluids would have to migrate through 7,000 feet of that solid rock. Once again, that's about the same distance as from the West front of the Capitol all the way to the Washington Monument—of solid rock. That fluid migration can't happen and it doesn't happen.

Given these facts, what can possibly explain calls to regulate fracking from Washington, DC.? It's simple: the Obama administration wants to regulate fossil fuels out of existence. And they haven't been shy about it. Energy Secretary Steven Chu actually said, "Somehow we have to figure out how to boost the price of gasoline to the levels in Europe." For my colleagues who might not know, prices are $8 per gallon in Europe. Or consider Alan Krueger of the Treasury Department, who said, "The Administration believes that it is no longer sufficient to address our Nation's energy needs by finding more fossil fuels. . . ."

Mr. Krueger's belief is now reality. Gas at the pump is fast approaching $4.00 a gallon. Drilling in Federal offshore waters is nearly non-existent. As for Federal lands, the Western Energy Alliance recently reported that oil and gas leasing has dropped by 67 percent since 2005.

If you think these data points are bad, they will grow far worse under EPA's cap-and-trade agenda. As part of that agenda, the agency is maneuvering to regulate hydraulic fracturing, a practice that has always been regulated by the states.

But testimony today will confirm that the states don't need EPA. The nation's immense shale deposits are predominantly located in states that effectively and efficiently regulate oil and gas. In states such as Pennsylvania, Arkansas, Oklahoma, Texas, Louisiana, West Virginia, Ohio, and North Dakota, a virtual boom in natural gas development is transforming America's energy security—due in no small measure to the absence of Federal regulation.

For this reason, let's keep the states in charge of hydraulic fracturing, for the benefit of consumers, jobs, economic growth and expansion, and our Nation's energy security.

Senator CARDIN. Chairman Boxer.

STATEMENT OF HON. BARBARA BOXER, U.S. SENATOR FROM THE STATE OF CALIFORNIA

Senator BOXER. Thank you, Senator Cardin.

Thank you for chairing this important hearing as Chairman of the Water and Wildlife Subcommittee.

First, just on another note, I want to express, as Chairman of this committee, I don't speak for all the Members. I do speak for the Members on my side of the aisle. We are grateful that the budget agreement does not include EPA riders and a poll today showed that 70 percent of the people agree with that.

Today, we are here to examine the public health and environmental impacts of natural gas drilling. Recent advancements in horizontal drilling and hydraulic fracturing have led to significant expansion in proving U.S. natural gas reserves, and we are glad to see that we can in fact extract natural gas because now it is actually economically, where a few years ago it was not.

The discovery of new resources creates an opportunity for increased production of a cleaner, domestically produced fuel. One of the key reasons for the increase in natural gas reserves is the discovery of the Marcellus Shale in the Appalachian region of the United States, which underlays portions of Virginia, West Virginia, Ohio, Maryland, Pennsylvania and New York.

With drilling in this part of the country like to increase exponentially in coming years, it is critical that we ensure that efforts to extract natural gas do not threaten the air we breathe and the water we drink.

I want to thank Senator Casey for really taking this issue on in a very responsible way. I again want to thank Senator Cardin because his State has a lot at stake here as well.

I am one who believes that this committee's oversight effort is important because there are questions that need to be answered and if we follow the science, it will lead us the right way. A recent series of investigative reports in the *New York Times* highlighted some of the potential risks, I say potential risks, of natural gas drilling and the inconsistent efforts to regulate this booming industry.

For example, the Times reported that the hydraulic fracturing process wastewater is often contaminated with pollutants, including toxic metals, highly corrosive salts, carcinogens such as benzine, and radioactive elements. These are facts. This is not a statement pro or con. These are facts.

A large amount of this wastewater is disposed in municipal sewage treatment plants that may or may not be equipped to remove the contaminants. These plants can discharge harmful levels of radiation and toxic substances into local waterways, and the solid waste produced may contain an array of toxins.

Without the proper oversight, the disposal of drilling wastewater poses threats to aquatic life and human health, especially when public drinking water systems rely on waterways where waste is being discharged. Concerns have also been raised that chemicals contained in the fluids used in the hydraulic fracturing process can contaminate groundwater.

However, Federal and State regulators and concerned citizens frankly haven't had all the information they need to determine whether drilling was causing groundwater contamination. Historically, some companies have limited access to information on the chemicals they use in their drilling fluids.

The Federal Government does not require drilling operators to fully disclose the chemicals they are injecting into the ground. Some States such as Wyoming now require disclosure of chemicals used in the fracking process. So I agree that some States are taking responsible action here.

The industry has also recently launched a voluntary disclosure effort with the Groundwater Protection Council. That is encouraging, too, but we have a long way to go before full disclosure is a consistent and industry-wide practice.

I believe in disclosure. Let the facts come out and we will make a reasonable decision, I believe. So I have highlighted only a few of the health and environmental issues that have been associated with natural gas drilling. Additional issues include air pollution, impacts on water supply due to the millions of gallons of water that are needed at each natural gas well.

So given the array of potential impacts and the need for more studies, the State of New York is taking a time out of hydraulic fracturing, choosing to fully study the issues first before allowing widespread drilling. So New York and other States are taking action here.

The U.S. EPA has also been directed by Congress, directed by Congress, to study the impact of hydraulic fracturing on water supplies. I expect the Agency will use an independent, comprehensive and scientific process to provide Congress with unbiased information. There is much that we need to learn so that we can move forward in a way that ensures safe and responsible drilling that is protective of our air and water. I think those have to go together.

This hearing is an important step in the EPW Committee's oversight on this issue and I certainly look forward to hearing from my colleagues and the other members of the panel.

Thank you.

Senator CARDIN. Senator Barrasso.

STATEMENT OF HON. JOHN BARRASSO, U.S. SENATOR FROM THE STATE OF WYOMING

Senator BARRASSO. Thank you very much, Mr. Chairman.

When it comes to American energy, we need it all. Oil and natural gas are a critical part of the mix. In my home State, we are very familiar with energy exploration. We have just about everything, from oil and gas to coal to wind, and these resources provide a great opportunity for our State and our Nation. It means jobs and economic security, as well as energy security.

Wyoming right now ranks second in the country in natural gas production. The oil and gas industry supports nearly 20,000 jobs in the State of Wyoming and we are talking about a State with a population of only about a half million people. The revenues generated from oil and gas exploration are invested right at home. It helps build schools, roads and water systems. It also helps send kids to college in our State through the Hathaway Scholarship Program.

Senator Inhofe gave a very compelling litany of success stories from across the country. I want to share a letter from the Wyoming Oil and Gas Conservation Commission. The Commission regulates oil an gas activities, including hydraulic fracturing in Wyoming. Here are a couple of quotes: "Wyoming has no documented cases of groundwater contamination caused by hydraulic fracturing. From 1999 to 2010, over 46,000 individual hydraulic fracturing well stimulation treatments were performed in Wyoming. Almost 100 percent of oil and gas wells drilled in Wyoming require hydraulic fracture stimulation to be commercial."

I request a copy of this letter be placed in the record.

Senator CARDIN. Without objection.

Senator BARRASSO. Thank you, Mr. Chairman.

[The referenced document follows on page 262.]

Senator BARRASSO. It provides details about my home State's rules for hydraulic fracturing. In Wyoming, we have been producing oil and gas for a long time. The letter mentions over 46,000 of these procedures from 1999 to 2010 alone, but our experience goes way back to the 1950's. Wyoming continues to be a leader ensuring that the appropriate safeguards are in place for drilling and for hydraulic fracturing. We take this issue very seriously and I appreciate Senator Boxer's comments about Wyoming doing it right.

It is about both our environmental stewardship and about jobs. The State demonstrated this when it updated its rules just this last year. The changes include increased transparency requirements for hydraulic fracturing. Industry is required to disclose all the chemicals used in well stimulation before and after hydraulic fracturing.

Most of America's oil and gas production is dependent on hydraulic fracturing. Without it, America's vast energy resources will remain locked away and we will become increasingly dependent on foreign energy, a threat to our energy security, our financial security, and our national security.

Thank you, Mr. Chairman.

Senator CARDIN. Thank you.

We will now turn to our colleagues as our first panel. We will start with Senator Cornyn.

STATEMENT OF HON. JOHN CORNYN, U.S. SENATOR FROM THE STATE OF TEXAS

Senator CORNYN. Thank you, Chairman Cardin, and thanks to Chairman Boxer, the Chairman of the full committee, and Senator Inhofe, the Ranking Member, and Senator Barrasso. It is good to be here with you today.

As Senator Inhofe noted, fracking has been around a long time, about 60 years. What has changed the state of play, so to speak, has been the advent of horizontal drilling, which if you fly into Dallas-Fort Worth Airport, you will be met with scenes actually of active drilling going on there thanks to the directional drilling that is capable from a single platform of doing out a mile or more into some of the shale formations.

I am glad to have the opportunity to share the perspective of my State on this practice, which I am proud to say we helped develop, and which is essential to the development of three shale plays in our State: the Barnett Shale around Fort Worth; the Haynesville Shale out in East Texas; and the Eagle Ford Shale.

I want to focus on three points. Texas and the United States, as you already stated, has a bountiful supply of natural gas. This has implications for job creation and our economy and national security. States are effectively regulating hydraulic fracturing already. Federal regulation by the EPA would inevitably lead to duplicative regulation, bureaucratic delays and diminish the production of this important energy resource.

In Texas, the oil and gas industry provides more than 1.7 million jobs and accounts for nearly 25 percent of our State's economy. Over 11,000 wells have been completed in the Barnett Shale, which as I said, is in the Dallas-Fort Worth area, one of the Nation's most active and largest unconventional natural gas fields. The Barnett Shale contributes over 20 percent of the total Texas natural gas production.

In South Texas, a very exciting development there with the Eagle Ford Shale. According to a recent study by the University of Texas at San Antonio, the long-term regional implications of the boom in South Texas are staggering. According to a study by the University, under modest assumptions, by 2020 the Eagle Ford Shale is expected to account for close to $11.6 billion in gross State product; $21.6 billion in total economic output impact; and support close to 67,000, roughly 68,000 full-time jobs.

The Haynesville Shale in East Texas and Louisiana was not commercially viable until a few years ago, but is now thanks to advancing technology. I recently went to a drilling rig outside of Nacogdoches, TX that represents the latest improvements on drilling, using more energy-efficient engines, leading to shorter drilling times, and reducing the impact on surrounding areas.

The proliferation of these domestic resources has contributed to Texas' ability, if not unique, nearly unique in this recession, to actually add jobs to our economy. Yet the job creators and workers on this particular rig were anxious about what they could expect from Washington in terms of additional and duplicative regulation.

As you know, hydraulic fracturing has been used safely in tens of thousands of wells already. This practice has been studied extensively by the Environmental Protection Agency, Groundwater Protection Council, the Interstate Oil and Gas Compact Commission. In each case, hydraulic fracturing has been judged to be environmentally sound.

At every step in the drilling process, energy producers are subject to State regulations already, as well as Federal requirements under the Occupational Health and Safety Administration, the Environmental Response, Compensation and Liability Act, and the Toxic Substances Control Act. So as you can see, the Federal Government is already actively involved.

This week, the Groundwater Protection Council and the Interstate Oil and Gas Compact Commission unveiled a landmark web-based national registry for the disclosure of chemical additives used in the fracking process. As alluded to by Chairman Boxer, this is important information. Energy companies now have a single source to publicly disclose these fluids on a well by well basis. So State regulators are already aware of what chemicals are being used and hydraulic fracturing has not been the culprit in water contamination. This registry is an important tool for the education of the public.

However, I must say that I'm joined here at the table by my good friend Senator Casey, who I know is proposing legislation called the FRAC Act that would go beyond public disclosure of chemical additives and give the EPA direct regulatory authority over hydraulic fracturing for the first time in our Nation's history.

In my view, there is no need to destroy the current partnership between State and Federal regulators and put the EPA in the driver's seat. We have seen the EPA through aggressive regulatory efforts engage in a lot of activity which, frankly, is harmful to our economy and we have seen what happens when over-regulation and misinformation becomes the common narrative.

Additional layers of red tape, lawsuits and restrictions can create a death by a thousand cuts that run independent producers out of business and take with them valuable jobs, as well as local, State and Federal tax revenue.

Without hydraulic fracturing, access to potentially massive natural gas resources in America's shale regions would be substantially restricted.

I thank very much the committee for having the hearing and thank you for having me come testify on a very, very important topic.

Thank you.

[The prepared statement of Senator Cornyn follows:]

STATEMENT OF HON. JOHN CORNYN, U.S. SENATOR FROM THE STATE OF TEXAS

Chairman, members of the Subcommittee, thank you for having me testify on the topic of hydraulic fracturing, which is a critical technology for increasing domestic natural gas production. I am glad to have the opportunity to share my state's perspective on this practice—which, I am proud to say, we helped develop, and is essential to the development of the three shale plays in my home state: the Barnett, the Haynesville, and the Eagle Ford.

I'd like to focus on a few key points. (1) Texas and the United States have a bountiful supply of natural gas with significant, positive implications for our economy, and our future energy security. (2) States are effectively regulating hydraulic fracturing. (3) Federal regulation by the Environmental Protection Agency (EPA) would inevitably lead to duplicative regulation, bureaucratic delays, and diminish the production of this important energy resource.

Over the past decade, the combination of horizontal drilling and hydraulic fracturing has allowed access to large volumes of shale gas that were previously uneconomical to produce. Production of shale gas is expected to continue to increase, and constitute 45 percent of U.S. total natural gas supply in 2035, as projected in the 2011 Annual Energy Outlook by the Energy Information Administration.

In Texas, the oil and gas industry provides more than 1.7 million jobs and accounts for nearly 25 percent of the state's economy. Over 11,000 gas wells have been completed in the Barnett Shale, one of the nation's most active and largest unconventional natural gas fields. The Barnett Shale production currently contributes over 20 percent of total Texas natural gas production.

In South Texas, the Eagle Ford Shale is also booming. According to a recent study by the University of Texas at San Antonio, the long-term regional implications of the boom are staggering. According to a study by the university: "Under modest assumptions, by 2020 the Eagle Ford shale is expected to account for close to $11.6 billion in gross State product, $21.6 billion in total economic output impact and support close to 67,971 full-time jobs in the area."

The Haynesville Shale in East Texas and Louisiana was not commercially viable a few years ago, but is today thanks to technology. I recently visited a new drilling rig in Nacogdoches, Texas that represents the latest improvements in horizontal drilling—using more energy efficient engines, leading to shorter drilling times and reducing the impact on surrounding areas. The proliferation of these domestic resources has contributed to Texas' ability to add jobs in the current economy. Yet the job creators and workers on the rig were anxious about Washington's misguided policies.

Hydraulic fracturing has been used safely in tens of thousands of wells across the state. The practice has been studied by the EPA, Groundwater Protection Council (GWPC) and the Interstate Oil and Gas Compact Commission (IOGCC). In each case, hydraulic fracturing was judged to be environmentally sound.

At every step in the drilling process, energy producers are subject to State regulations as well as Federal requirements through the Occupational Safety and Health Administration, the Environmental Response, Compensation and Liability Act and the Toxic Substances Control Act.

This week, the Groundwater Protection Council (GWPC) and the Interstate Oil and Gas Compact Commission (IOGCC), unveiled a landmark web-based national registry for the disclosure of the chemical additives used in the fracturing process. Energy companies now have a single source to publically disclose these fluids on a well-by-well basis. Though State regulators are already aware what chemicals are being used, and hydraulic fracturing has not been the culprit in water contamination, this registry is an important tool for the education of the public.

However, legislation introduced by my friend, Senator Casey, known as the FRAC Act, would go beyond public disclosure of chemical additives and give the EPA direct regulatory authority over hydraulic fracturing for the first time in history. In my view, there is no need to destroy the current partnership between State and Federal regulators and put the EPA in the driver's seat. Unfortunately, we've seen what over-regulation and misinformation can do to our energy supplies.

Additional layers of Federal red tape, lawsuits, and restrictions can create "death by a thousand cuts" that run independent producers out of business—and take with them valuable jobs, as well as local, State and Federal tax revenue. Without hydraulic fracturing, access to potentially massive natural gas resources in America's shale regions would be substantially restricted.

Thank you.

Senator CARDIN. Thank you, Senator Cornyn.

Senator Casey.

STATEMENT OF HON. ROBERT P. CASEY, JR., U.S. SENATOR FROM THE COMMONWEALTH OF PENNSYLVANIA

Senator CASEY. Thank you, Mr. Chairman.

I want to thank you for this hearing and Chairman Boxer, thank you as well for your testimony, and Ranking Member Inhofe, and now we are joined by Senator Lautenberg and Senator Barrasso.

I do want to thank Senator Cornyn for his testimony. Let me first of all ask consent that I can place my whole statement in the Record.

Senator CARDIN. Without objection.

Senator CASEY. Thank you. I will be rather brief.

I will start with history. In our State, we went through most of the 19th century and roughly about half of the 20th century not getting it right as it relates to the extraction of a natural resource, in this case coal, and balancing that with environmental regulations to make sure we were protecting public health and the environment.

After 1950, we began to get it right in our State. Our State passed legislation like the Clean Streams Law in the early 1960's. As time went on, we started to do a much better job of regulating and making sure that we are getting that balance right.

Today, we have to get it right. We have to be able to at the same time create jobs, and there has been a tremendous increase in jobs in Pennsylvania as a result of natural gas extraction. We also have, of course, the availability of a domestically produced source of energy, and that is good news. We need to pursue that.

But we have to balance those with the kind of protections for public health and safety, as well as making sure that groundwater and drinking water is protected. I will speak about my legislation in a moment, but it reached a point in our State where after all that history and all of that learning and experience, that our State constitution was amended in the early 1970s. It is a very simple statement, but it is an important statement I think for our Commonwealth and I think for our country.

Article I, Section 27 of the Pennsylvania constitution says the people shall have a right to clean air, pure water, and to the preservation of the natural, scenic, historic and aesthetic values of the environment. It goes on to say that that obligation means that we hold the environment as trustees for future generations.

That is the directive from our State's constitution. It is not optional. It is not a maybe. It is not a hope you can do it. It is a directive, a constitutional directive. So I live in a State where that directive is very important to the Commonwealth and very important I think to people across the State.

I think we can get this right. I don't think there is any question about it. But unfortunately, now even though this process has been around a while, the hydraulic fracturing process, there is still a lot of questions about whether or not it will have some of the environmental impacts that some are concerned about.

I don't think it has to in any way slow things down. These questions are being raised in the State where over a four or 5-year period of time we were averaging only 17 wells drilled a month. Now, we are well are well above I think the last number I saw was 120 wells a month are being drilled. So nothing has slowed down here.

There is tremendous growth of this industry and tremendous opportunity with it. But as we are doing that, we have to make sure that we get it right.

Let me just highlight. I have three bills, one that deals with emergencies as well sites; one that deals with job training. I will skip over those. They will be in my testimony.

But just on the hydraulic fracturing, the so-called FRAC Act. Basically, what we are trying to do is amend the Safe Drinking Water Act, in particular the definition of "underground injection" to include underground injection of fluids or propping agents used for hydraulic fracturing operations related to oil and gas production activities. It is very simple. We are trying to close the loophole that is in the law as it stands now.

Second, it would require public disclosure of the chemical constituents, but not the proprietary information. Of course, if you analogize that to ingredients in something you would be making, baking a cake or something like that, we are not asking in this legislation that the proprietary information is made a part of public disclosure, but just the chemicals.

The good news is here that we are getting a good bit of cooperation and help from the industry. Companies are disclosing. We will have some debates about the level and nature of disclosures, but I think the most difficult issue and the one that will cause the most conflict is the question of regulation.

I am in favor of a national standard. Why should we have a set of tough environmental rules that protect drinking water and groundwater in one State, and have a State next door or across the country have a whole other set of rules.

So I think we can get this right. I appreciate the opportunity to speak about this, and I am grateful to be joined by Senator Cornyn here at the table. I think we are both running out the door.

[The prepared statement of Senator Casey follows:]

STATEMENT OF HON. ROBERT P. CASEY, JR., U.S. SENATOR FROM THE COMMONWEALTH OF PENNSYLVANIA

Good morning. I want to thank the members of the committee and subcommittee for holding this morning's hearing As you know, natural gas drilling is an issue of immediate national relevance and vital importance to my home state. Thank you for the opportunity to testify today.

I. NATURAL GAS, JOBS, AND ENERGY SECURITY

I support the responsible development of domestic natural gas resources and believe that it has the potential to produce significant environmental and economic benefits. Natural gas is playing an increasingly substantial role in our energy portfolio as we transition to a new energy future, and we are fortunate to have this domestic resource to help meet our growing demands. President Obama, in his speech introducing the "Blueprint for a Secure Energy Future," noted that, "In terms of new sources of energy, we have a few different options. The first is natural gas." While we *must* push harder for renewables such as wind and solar, all forms of power generation must remain under consideration. Natural gas offers enormous potential for our transportation and power needs.

Technological advances are enabling amazingly high yields from previously inaccessible sources such as the Marcellus Shale. Hydraulic fracturing is an American-born technology prime for export, but importers may not embrace it until it is proven to be safe and sustainable. While hydraulic fracturing has been in use for over 50 years, it is a markedly different technology from previous decades. It is now used in conjunction with horizontal drilling, in a much greater proportion of wells drilled, uses much larger total amounts of water and chemicals, and is rapidly expanding in geographic scope, most notably in the Marcellus Shale.

It is mind-boggling how deep and how far we are now able to accurately drill into targeted areas and extract out tiny pockets of gas trapped in hard rock. The Commonwealth of Pennsylvania is experiencing a natural gas boom. An average of 120 wells per month were drilled in the Marcellus Shale in 2010, versus 17 a month in the preceding 4 years. Palpable optimism exists around the energy resource advantage that American natural gas reserves give us on a global scale. But it is incumbent on us to *unequivocally* ensure its practice as a safe, clean, and stable energy extraction method.

II. HISTORY AND EXAMPLES

In the last 150 years, prospectors and energy companies have drilled as many as 12 million holes across the United States in search of oil and gas. Edwin Drake drilled the Nation's first commercial oil well near Titusville, PA, in 1859. People have since drilled wells as they pleased all across the country. Hundreds of thousands of these wells were abandoned and forgotten, often leaving no records of their existence. Some States did not develop modern regulations until the second half of the 20th century. In the early days, the industry was dominated by "wildcatters" looking to get rich quick. Some say that what is happening now is on par with a gold rush from back then. I don't believe that the miners of yore, or present-day drillers, intentionally sought to do damage to the communities they left behind. But my State bares the burden of past mining and drilling practices that have left environmental impacts that we continue to face. Most of these were created in previous generations when Federal regulations that promoted responsible development did not exist. We have old natural gas wells that were not capped and leaked methane into homes. We have acid mine drainage that we spend millions of dollars every year to remediate. There are lessons in these examples from which we need to learn.

For Pennsylvania and other States sitting on top of the Marcellus Shale formation, the rapid growth of gas drilling may increase the danger of oil, gas or brine-laden water pathways up to groundwater supplies or to the surface. The protection of underground water sources is especially important to Pennsylvania because we have the second highest number of private drinking water wells in the Nation; 3 million Pennsylvanians are dependent on private wells to provide safe drinking water to their homes. Every day I hear from Pennsylvanians who worry about their future access to safe drinking water and about explosions caused by gases migrating up from the deep. There continue to be incidents in Pennsylvania that could have, and should have, been averted. These cases raise the question of whether the necessary steps have been taken to protect families and communities against potential detrimental side effects of drilling.

While these cases may be anomalies, they are highly visible calamities. As with other high-impact incidents, such as the Gulf oil tragedy, they can serve to stall, or even halt, development of domestic energy production. Their impacts stretch beyond tragic public health and environmental consequences to lost jobs and the economy.

I commend my home State of Pennsylvania and the other States that have been taking steps to strengthen regulations and oversight of gas drilling with the goal of protecting the environment and public health. However, this is an industry without widely held and consistent best management practices, such as for controlling the quality of cementing and well casing. This has led to State-by-State variability in factors that are critical to ensuring the integrity of wells and protecting water resources.

III. FRAC ACT, MARCELLUS ON-THE-JOB ACT, AND THE FASTER ACT

There is no reason that we should be forced to choose among adequate environmental protection, energy security, and economic gain. In addition to helping to secure an Environmental Protection Agency study on fracking, I introduced a trio of related Bills:

- The Fracturing Responsibility and Awareness of Chemicals (FRAC) Act would increase disclosure and regulation of chemicals that could enter Pennsylvania's drinking water supply;
- The Faster Action Safety Team Emergency Response (FASTER) Act would improve safety for workers and emergency response procedures at drilling sites; and
- The Marcellus Shale On-the-Job Training Act would promote job training to help give Pennsylvania workers the skills needed to get jobs in the natural gas industry so that workers are not shipped in from out-of-state.

If passed, the Fracturing Responsibility and Awareness of Chemicals (FRAC) Act, S. 587, would,

- amend the Safe Drinking Water Act definition of "underground injection" to include the underground injection of fluids or propping agents used for hydraulic fracturing operations related to oil and gas production activities;
- require public disclosure of the chemical constituents (but not the proprietary chemical formulas) used in the fracturing process to State agencies prior to fracking, as well as after completing fracking, which will then be made public via Website; and
- require disclosure of a propriety formula to the State, EPA Administrator, or treating physicians or nurse in the case of a medical emergency. I view this as a simple matter of citizens having a right to know about any risks in their community.

I have received questions as to how the FRAC Act would work. It is my understanding that the FRAC Act would add fracking back to EPA's underground injection control program, from which hydraulic fracturing was exempted in 2005. Under the current underground injection control program, States can request primacy over the process. EPA would approve a State's request for primacy if the State had adequate laws and regulations in place to protect the environment. When States have primacy, they are responsible for the permitting and enforcement process, but EPA could step in if a State is irresponsible in its implementation.

I introduced S. 587, the FRAC Act, and its two corresponding bills on March 15, 2011. The FRAC Act was referred to this committee.

The Marcellus Shale On-the-Job Training Act, S. 588, is with the Senate Committee on Health, Education, Labor, and Pensions. It would amend the Workforce Investment Act of 1998 to require the Secretary of Labor to make discretionary grants to local areas for adult on-the-job training or dislocated worker on-the-job training as worksites directly related to the exploration for, production of, and transportation of natural gas from the Marcellus Shale formation.

The Faster Action Safety Team Emergency Response (FASTER) Act, S. 589, has been referred to the Senate Committee on Health, Education, Labor, and Pensions. It would ensure that the citizens and environment are protected from any emergency situations that may arise. The FASTER Act of 2011 provides the Occupational Safety and Health Administration with the ability to draft regulations that will enhance emergency response procedures at oil and gas wells.

Specifically, the FASTER Act provides OSHA the power to draft regulations that will require operators to:

- Have an employee, knowledgeable in responding to emergency situations, present at the well at all times during the exploration or drilling phase;
- Make available a certified response team, within one hour of ground travel time, if an emergency situation arises;
- Contact local first responders within 15 minutes of the commencement of an emergency situation;
- Contact OSHA within 1 hour of the commencement of an emergency situation;
- Contact the National Response Center within 1 hour of the commencement of an emergency situation;
- Provide communication technology at the well site (e.g., mobile communication or satellite phone);
- Provide annual training to local first responders on the hazards of a well site and proper emergency response techniques; and
- File an annual report with OSHA that names the certified response team assigned to each well of the operator.
- OSHA will have 18-months to finalize the regulations under this Act. The Act will allow OSHA to define the term 'emergency situation.'

In closing, I support responsible gas exploration, yet I strongly feel that we must protect against repercussions that not only harm the environment and put people at risk, but also hurt business and affect the economy. Damaging incidents can spark strong backlashes and end up stalling economic development. We are fortunate to have an abundance of natural gas, but it must be developed in a manner that fully *protects* human health and the environment, while *creating* economic benefits.

Thank you again for allowing me to testify here today.

Senator CARDIN. Right. Senator Casey, let me thank you very much for the contribution that you are making to this debate. I think your legislation is one we obviously want to consider very closely.

Senator Cornyn, we thank you very much. Our objectives are the same. We know we have a large amount of natural gas and we want to make sure that we can get that safely and use it for our energy security here in America.

With that, the two of you are excused. Thank you very much.

The first panel will consist of Hon. Robert Perciasepe, the Deputy Administrator of the Environmental Protection Agency.

Mr. Perciasepe, it is nice to have you back before the committee. You may proceed as you wish. Your entire statement will be made part of our record.

STATEMENT OF HON. ROBERT PERCIASEPE, DEPUTY ADMINISTRATOR, U.S. ENVIRONMENTAL PROTECTION AGENCY

Mr. PERCIASEPE. Madam Chair, Mr. Chairman and Ranking Member Inhofe, thank you for inviting me to testify today. I am pleased to be here to discuss natural gas production and EPA's role in ensuring that public health and the environment are protected.

Let me begin my remarks by saying that natural gas is a very important fuel for our country. It can enhance our domestic energy options, reduce our dependence on foreign supplies, and serve as a bridge fuel to the future and to renewable energy sources.

Produced responsibly, natural gas has the potential to improve air quality, stabilize energy prices, and provide greater certainty about the future energy reserves.

As President Obama said in a recent town hall meeting, "Recent innovations have given us the opportunity to tap large reserves of natural gas, perhaps a century's worth, in the shale under our feet. Now we have to make sure we are doing it safely without polluting our water supplies."

In addition, the President has ordered EPA, the Department of Interior and the Department of Energy to work together with industry, the environmental community and States to come up with best practices for environment and safety.

Making sure our water supply is safe is what I would like to talk about today. The Clean Water Act and the Safe Drinking Water Act are the primary statutes we use to ensure that natural gas extraction through a process called hydraulic fracturing or fracking does not impair water quality. We believe natural gas can be and must be extracted responsibly in a way that secures its promise for the benefit of all.

If improperly managed, hydraulic fracturing could potentially result in public health and environmental impacts at any time in the life cycle of the well and its associated operations. Such impacts to water could include stress on surface water and groundwater supplies, given the use of fresh water for these operations; potential contamination of drinking water aquifers, resulting from faulty well construction and completion; and compromised water quality due to the disposal of contaminated wastewater. These contaminants could include organic chemicals, metals, salts and radionuclides.

Where we know problems exist, EPA will not hesitate to protect Americans' whose health may be at risk. We remain committed to working with State officials who are on the front lines of permitting and regulating natural gas production activities. EPA will not only use the authority that Congress has given it, but we are also leading on understanding the science behind potential drinking water contamination from fracking.

As you know, EPA launched a study last year to understand the relationship between hydraulic fracturing and drinking water resources. When complete, this peer-reviewed research study will help us better understand the conditions that may be associated with the potential contamination of drinking water resources, as well as factors that may lead to human health exposure and risk. While we await the results of this study, we will also use our legal authorities where appropriate.

While Congress specifically exempted selected oil and gas production activities from several environmental laws, a number of environmental protections continue to apply. For example, while the Energy Policy Act of 2005 excluded hydraulic fracturing for oil and gas production from permitting under the State Drinking Water Act Underground Injection and Control Program, these activities are still regulated under the Safe Drinking Water Act when diesel fuels are used as fracking fluids. Also flow-back and produced water through injection is still regulated under the Safe Drinking Water Act.

In addition to our authorities under the Safe Drinking Water Act, EPA regulates wastewater from oil and gas wells under the Clean Water Act when they are discharged into publicly owned treatment works and surface waters. Under both of these laws, States play a major, if not leading role in its implementation. For States with fully delegated programs, including many in the Marcellus Shale region, States have the responsibility in making sure the laws are followed. EPA provides guidance to the States on how to follow these rules and to make sure that they are addressing all the threats to public health.

The issues surrounding natural gas extraction are lengthy and complicated. By helping manage environmental impacts and addressing public concerns, natural gas production can and will proceed in a responsible manner that protects public health and enhances our domestic energy options.

I will be happy to take any questions at this time, Mr. Chairman.

[The prepared statement of Mr. Perciasepe follows:]

TESTIMONY OF
BOB PERCIASEPE
DEPUTY ADMINISTRATOR
U.S. ENVIRONMENTAL PROTECTION AGENCY
BEFORE THE
SUBCOMMITTEE ON WATER AND WILDLIFE
COMMITTEE ON ENVIRONMENT AND PUBLIC WORKS
UNITED STATES SENATE

April 12, 2011

Good morning, Mr. Chairman and Members of the Subcommittee. I am pleased to be here today to discuss EPA's role in ensuring that public health and the environment are protected during natural gas extraction and production activities.

Natural gas can enhance our domestic energy options, reduce our dependence on foreign supplies, and serve as a bridge fuel to renewable energy sources. If produced responsibly, natural gas has the potential to improve air quality, stabilize energy prices, and provide greater certainty about future energy reserves.

While natural gas holds promise for an increased role in our energy future. EPA believes it is imperative that we access this resource in a way that protects human health and the environment.

Like you, we have heard the public's concerns about the safety of natural gas production and the potential impacts of shale gas development on American communities. As we listened to citizens at public meetings across the country last year, we heard the concerns many have for their families, their communities, the water, the air, and the land. We also heard from citizens who expressed how much their communities sorely need the income that could be gained from natural gas production.

We believe that this important resource can be – and must be – extracted responsibly, in a way that secures its promise for the benefit of all.

If improperly managed, natural gas extraction and production, including hydraulic fracturing, a technique for extracting natural gas, may potentially result in public health and environmental impacts at any time in the lifecycle of a well and its associated operations. Such impacts may include:

- stress on surface water and groundwater supplies from the withdrawal of large volumes of water used in drilling and hydraulic fracturing;
- potential contamination of drinking water aquifers resulting from faulty well construction and completion;
- compromised water quality due to challenges with managing and disposing of contaminated wastewaters, known as flowback and produced water, where contaminants could include organic chemicals, metals, salts and radionuclides; and
- impaired air quality from hazardous air pollutants such as benzene and the potent greenhouse gas methane.

Where we know problems exist, EPA will not hesitate to protect Americans whose health may be at risk, and we remain committed to working with state officials, who are on the front lines of permitting and regulating natural gas production activities.

EPA has an important role to play in ensuring environmental protection and in working with federal and state government partners to manage the benefits and risks of shale gas production. We must effectively address concerns about the consequences of shale gas development using the best science and technology. To this end, we are working in the following areas, among others, with all of our stakeholders, including other federal and state agencies, the oil and gas industry, and the public health community to evaluate and address the potential environmental issues related to shale gas.

Research:

At the direction of Congress, EPA launched a study last year to understand the relationship between hydraulic fracturing and drinking water resources-- a study that has already engaged thousands of Americans across the country who are currently living in areas where hydraulic fracturing is taking place. When complete, this peer-reviewed research study will help us better understand potential impacts of gas extraction and production on drinking water resources and factors that may lead to human exposure and risks, while reducing scientific uncertainties about environmental impacts from those processes.

As part of this effort, EPA required information from nine oil and gas service companies conducting hydraulic fracturing regarding the chemical composition of the fracturing fluids they are injecting into the ground. EPA has conducted stakeholder outreach during development of the study plan, including opportunity for public comment. The draft study plan is being reviewed by EPA's Science Advisory Board and it included an opportunity for public comment. The initial study results are expected to be available in late 2012.

Programmatic Activities:

While Congress specifically exempted selected oil and gas production activities from several environmental laws, a number of environmental protections continue to apply. For example, while the Energy Policy Act of 2005 excluded hydraulic fracturing for oil and gas production from permitting under the Safe Drinking Water Act's (SDWA) Underground Injection Control (UIC) Program, these activities are still regulated under the SDWA when diesel fuels are used in fracturing fluids. Also, flowback and produced water disposal through injection is still regulated under the SDWA.

EPA regulates waste waters from oil and gas wells under the Section 301(b) and 402 (a) of the Clean Water Act (CWA) when they are discharged into publicly owned treatment works (POTWs) and surface waters. To address public health concerns from air emissions, Clean Air Act (CAA) provisions for New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants, and Mandatory Reporting of Green House Gases apply to energy extraction.

Under several of the principal environmental statutes we administer, EPA has a number of activities underway, which I would like to outline for you.

CWA and SDWA

Under the CWA and SDWA, EPA works with states to ensure that gas extraction is carried out consistent with CWA and SDWA regulations to protect water and drinking water. For example, on March 16, 2011, we released shale gas extraction Frequently Asked Questions (FAQs) intended to serve as CWA guidance to state and federal permitting authorities within the Marcellus Shale region in addressing treatment and disposal of wastewater from shale gas extraction. The FAQs discuss the wastewater issues and pollutants associated with shale gas extraction and how they can be addressed under existing regulations. Relevant regulations that are discussed cover oil and gas extraction, centralized waste treatment, acceptance and notification requirements for publicly owned treatment works, pretreatment, and storm water. The FAQs should assist EPA and state personnel as they work with the regulated community to address shale gas extraction wastewater.

As part of its effluent guidelines planning process under CWA section 304(m), EPA is considering whether to initiate a rulemaking to revise these regulations to address coal bed methane extraction flowback waters. Also, in response to public comment, EPA is considering how best to address shale gas extraction wastewater discharges to POTWs under the CWA. Similarly, under SDWA's UIC program, EPA is working expeditiously to ensure the SDWA programmatic requirements related to hydraulic fracturing when using diesel fuels are implemented appropriately. We are coordinating with our state and Tribal co-regulators to ensure proper management of flowback and produced water disposed of via underground injection.

Clean Air Act (CAA)

A range of Clean Air Act (CAA) provisions apply to the oil and gas sector. Under the CAA New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants programs, EPA must review, and propose amendments, where warranted based on the reviews, to existing CAA regulations for oil and natural gas production, natural gas processing plants, and natural gas transmission and storage.

Subpart W of EPA's Greenhouse Gas Reporting Program requires companies to begin collecting methane emissions data as of January 1, 2011, and report the emissions for each year starting in 2011 by March 31 of the following year. This rule will increase the understanding of the location and magnitude of significant methane and other GHG emissions sources in the petroleum and natural gas industry. Increased information will help companies improve the efficiency of their operations and will result in cross-cutting benefits for public health, domestic energy supply, industrial efficiency and safety, and revenue generation through methane recovery and other emissions reduction efforts.

EPA's regulatory efforts will complement our Natural Gas STAR Program, a flexible, voluntary partnership between EPA and oil and natural gas operating companies which encourages companies both in the United States and internationally to adopt proven, cost-effective technologies and practices that improve operational efficiency and reduce methane emissions. Beginning in 1993, this successful voluntary program now has over 130 partner companies. Together we have identified over 80 technologies and practices that can cost-effectively reduce methane emissions from the oil and natural gas sector. (A list of these technologies is posted on the EPA Natural Gas STAR website: (http://www.epa.gov/gasstar/tools/recommended.html). These include methane emission reduction activities applicable to the largest natural gas industry methane sources: gas well liquid unloading, unconventional gas well completions and workovers, pneumatic devices, reciprocating and centrifugal compressors, crude oil and condensate tank vents and general fugitive emissions. Natural Gas STAR partners reported domestic emissions reductions of 86 Bcf, worth over $344 million, in 2009 and over 900 Bcf, worth over $4.4 billion, over the life of the program.

Enforcement

Under each of these statutes I just described, EPA has tools for enforcement and investigation to assure compliance with applicable requirements, and the Agency provides support and technical assistance to state programs, which have front-line responsibility for oversight of oil and gas drilling operations.

In April 2010 EPA announced an enforcement initiative for energy extraction sector for fiscal years 2011 through 2013. The initiative has twin goals: to take appropriate enforcement action where adverse impacts on air and water from energy extraction activities threaten human health, and to incorporate broad, company-wide injunctive relief in gas-related enforcement actions as a means of reducing human health and environmental impacts of the industry.

EPA retains authority to respond to imminent and substantial endangerments to public health or the environment under several statutes, including the Safe Drinking Water Act, the Clean Air Act, the Clean Water Act, the Resource Conservation and Recovery Act, the Toxic Substances Control Act, and the Comprehensive Environmental Response, Compensation, and Liability Act.

Conclusion

In conclusion, EPA is committed to using its authorities, consistent with the law and best available science, to protect communities across the nation from impacts to water quality, human health, and environment associated with natural gas production activities. We also commit to coordinating with our federal, state, and local partners as we move forward. By helping manage environmental impacts and address public concerns, natural gas production can proceed in a responsible manner, which protects public health and enhances our domestic energy options. We believe that by doing so, as a nation, together we can establish a sound framework that allows for the safe and responsible development of a significant domestic energy resource whose use brings a range of other important national security, environmental and climate benefits.

EPA Response to May 3, 2011 Hearing on "Natural Gas Drilling: Public Health and Environmental Impacts"- Questions for the Record

Senator Barbara Boxer

1. ***During the EPW hearing on April 12, you testified that the plain language of the Energy Policy Act of 2005 prohibits the use of diesel fuel in hydraulic fracturing without first obtaining a Safe Drinking Water Act (SDWA) Underground Injection Control (UIC) permit. Do you agree that the SDWA can currently be enforced with respect to the use of diesel fuel in hydraulic fracturing?***

Response:

EPA agrees that the SDWA can be enforced with respect to the use of diesel fuels in hydraulic fracturing. EPA will evaluate on a case-by-case basis any potential violations of the SDWA that it discovers from the injection of diesel fuels into wells.

2. ***Mr. Perciasepe, there have been reports in the media about significant air pollution from natural gas drilling. We have seen reports of ozone pollution in certain counties in Western States where the air quality is significantly above health standards. How is EPA addressing the threats to public health caused by air emission from natural gas drilling operations?***

Response:

EPA addresses air emissions from the oil and gas industry through both regulatory and voluntary programs. On the regulatory front, EPA has New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP) regulations designed to reduce emissions of volatile organic compounds (VOCs), sulfur dioxide (SO2), and air toxics from the oil and natural gas industry. On the voluntary front, EPA has implemented the Natural Gas STAR Program, which has achieved significant methane reductions by encouraging environmentally sound practices.

In a recent review of its air regulations, EPA determined that current regulations do not address air emissions from certain sources of VOCs in this sector, including hydraulically fractured wells. On July 28, 2011, EPA proposed a suite of highly cost-effective revisions to the NSPS and NESHAP that would address these findings and further reduce harmful air pollution from the sector while supporting the Administration's priority of continuing to expand safe and responsible domestic oil and natural gas production. The proposed rules would apply to oil and gas exploration and production and natural gas processing, transmission, and storage.

The proposed rules would cut smog-forming VOC emissions by nearly one-fourth across the regulated sector, including a nearly 95 percent reduction in VOCs emitted from new and modified hydraulically fractured gas wells. The VOC emission reductions from wells, combined with reductions from storage tanks and other equipment, are expected to help reduce ozone levels in areas where oil and gas production occurs. This significant reduction would be accomplished primarily through use of a proven technology – in use by many Gas STAR partners – to capture natural gas that currently escapes to the air. The captured gas would then be made available for sale.

In addition, the reductions would yield a significant environmental co-benefit by reducing methane emissions from new and modified wells. Oil and natural gas production and processing accounts for nearly 40 percent of all U.S. methane emissions, making the industry the nation's single largest methane source.

The comment period on the proposed rules was extended and closed November 30, 2011. EPA is under a court order to issue final rules by April 3, 2012.

With respect to voluntary programs, since 1993 EPA has been working with the oil and natural gas industry through the Natural Gas STAR Program to reduce methane emissions from all industry sources, including well drilling. Reducing emissions of methane, a potent greenhouse gas, has climate change benefits and also yields important air quality, human health, and financial benefits. Through the Natural Gas STAR program, EPA and partner companies have identified over 80 technologies and practices that can cost-effectively reduce emissions from the oil and natural gas sector, and Gas STAR partners have reported domestic emission reductions of 86 billion cubic feet (Bcf), worth over $344 million, in 2009, and reductions of greater than 900 Bcf, worth over $3.6 billion, over the life of the program.

To address air quality impacts associated with oil and gas activities on Federal Lands, EPA recently entered into a Memorandum of Understanding (MOU) with the U.S. Department of the Interior (DOI), and the U.S. Department of Agriculture (USDA) that outlines a number of steps the agencies will take to ensure that federal laws protecting air quality, human health, and the environment are balanced with the nation's energy needs. The MOU, signed on June 23, 2011, provides for early interagency consultation; common procedures for determining what type of air quality analyses are appropriate and when air modeling is necessary; and specific provisions for analyzing and discussing impacts to air quality and for mitigating such impacts as part of the environmental review process required by the National Environmental Policy Act (NEPA).

In addition, EPA's Office of Enforcement is investigating potential violations of the Clean Air Act (CAA) associated with natural gas extraction and production activities. As part of the Agency's Energy Extraction National Enforcement Initiative, EPA will take appropriate action to address violations of the Clean Air Act from this sector, particularly where there are potential impacts to human health.

3. ***Mr. Perciasepe, landowners who rely on drinking water from wells located near hydraulic fracturing operations need to know that their drinking water is safe. However, they may not have the necessary information on chemicals used in drilling operations to carry out baseline testing of their water supplies. Does EPA have any guidance to homeowners on the specific chemicals to include in baseline testing of their drinking water wells? Does EPA intend to issue such advice to the public?***

Response:

If citizens have concerns about the safety of their drinking water they should contact their public water system, state health department, or environmental agency for information on sampling and testing water. In Pennsylvania, the State has requested that public water systems test for chloride, sulfate, bromide, pH, and radionuclides (i.e., gross alpha, gross beta).

We have established a hotline for individuals to report any observed environmental concerns associated with drilling operations. Citizens may call 1-877-919-4EPA (toll free) or send reports by email to eyesondrilling@epa.gov.

While EPA currently does not have guidance on specific chemicals to include in baseline testing, the New York State Water Resources Institute (WRI) does provide detailed information on testing of private wells. WRI is a federally mandated institution helping to improve water management and has information available at http://wri.eas.cornell.edu/gas_wells_6_1489175471.pdf.

4. In your written testimony, you state that EPA is currently considering revising its Clean Water Act regulations establishing effluent limitation guidelines (ELGs) to address coal bed methane (CBM) flowback wastewater and that EPA is also considering how to best address shale gas process wastewater discharged to publicly owned treatment works (POTWs) or commercial centralized waste treatment facilities (CTWs). Please provide the Committee with an update concerning EPA's plans to address wastewater discharges, including revising the Clean Water Act ELGs for CBM and shale gas process wastewaters discharged to POTWs or CWTs.

Response:

On October 20, 2011, EPA announced that it will develop effluent guidelines for discharge of wastewater from the coalbed methane extraction industry and will develop pretreatment requirements for discharges of wastewater from the shale gas extraction industry. To ensure that these wastewaters receive proper treatment and can be properly handled by treatment plants, EPA will gather data, consult with stakeholders, including ongoing consultation with industry, and solicit public comment on a proposed rule for coalbed methane in 2013 and a proposed rule for shale gas in 2014.

Senator Benjamin L. Cardin

1. ***Does the Clean Water Act allow a wastewater treatment works facility to accept wastewater consisting of unknown contaminants? Does the Act allow a wastewater treatment facility to accept wastewater containing contaminants for which it does not have effluent limitations in its NPDES permit? Does the Act allow a wastewater treatment works to "pass through" contaminants that it cannot adequately treat, thereby passing the contaminants through to discharged water? Does the Act allow a publically owned treatment works facility to accept wastewater that may cause interference with the proper functioning of the treatment process? If the answer is no to any of these questions, please provide the reference in the Act which prohibits these actions. Further, for any question in which the answer is no, please indicate what actions EPA is taking to ensure that treatment works facilities comply with the provisions of the Clean Water Act?***

Response:

The CWA prohibits the discharge of pollutants by point sources into waters of the United States, except in compliance with certain provisions of the CWA, including section 402. 33 U.S.C. 1311(a). Section 402 of the CWA establishes the National Pollutant Discharge Elimination System ("NPDES") program, under which EPA, or an authorized state agency, may issue a permit allowing the discharge of pollutants into waters of the U.S. 33 U.S.C. 1342(a). When developing effluent limitations for an NPDES permit, a permit writer must consider limits based on both the technology available to control the pollutants (i.e., technology-based effluent limits) and limits that are protective of the water quality standards of the receiving water (i.e., water quality-based effluent limits). CWA section 301, 33 U.S.C. § 1311; 40 CFR 125.3(a). The technology-based requirements for direct discharges from oil and gas extraction facilities into surface waters are found in 40 Code of Federal Regulations (CFR) Part 435 (see response to question 7, below).

Section 308 of the CWA provides broad authority to require information from point sources in order to characterize the nature of their discharges. Pursuant to CWA Section 308, NPDES regulations at 40 C.F.R. § 122.21 provide specific requirements for the submission of information for owners or operators seeking an individual NPDES permit. In accordance with these regulations, it is the responsibility of the applicant to characterize the wastewater to be discharged from the permitted facility and to provide the information necessary for the permitting authority to make informed decisions.

In order to submit a complete NPDES permit application for an individual permit, the applicant must present data to properly characterize its discharge to enable a reasonable potential analysis to be completed by the permit writer at the time of permit issuance. 40 C.F.R. § 122.21(g)(7). In addition to data specifically required by permit applications, 40 C.F.R. § 122.21 allows permitting authorities to request any additional data as necessary to support an assessment of potential water quality impacts.

The procedure for determining the need for Water Quality Based Effluent Limitations (WQBEL) is called a "reasonable potential" determination. Under EPA's regulations at 40 C.F.R. § 122.44(d)(1)(i), WQBELs are required for all pollutants that the permitting authority determines "are or may be discharged at a level [that] will cause, have the reasonable potential to cause, or contribute to an excursion above any [applicable] water quality standard, including State narrative criteria for water quality." Thus, if a pollutant discharge has the reasonable potential to cause or contribute to an excursion above any applicable water quality standard – including narrative criteria – the discharger's

NPDES permit must contain a WQBEL for that pollutant. 40 C.F.R. § 122.44(d)(1)(iii)-(vi). Conversely, if a pollutant discharge does not have the reasonable potential to cause or contribute to an excursion above any applicable water quality standard, a WQBEL is not necessary for that pollutant. If that pollutant in the discharge is also not subject to applicable technology-based requirements, then the permit would not need an effluent limit for that pollutant.

In addition to direct discharges, wastewaters may be indirectly discharged into waters of the U.S. through sewer systems connected to publicly owned treatment works (POTW) that discharge directly to waters of the U.S. or by being introduced by truck or rail into a POTW that discharges directly. EPA regulations set standards for the pretreatment of wastewater introduced to a POTW including prohibiting introduction of wastes that interfere with, pass through or are otherwise incompatible with POTW operations. 33 U.S.C. § 1317(b)(1). EPA has developed other nationally applicable pretreatment standards under section 307(b) in its General Pretreatment Regulations for Existing and New Sources of Pollution (Pretreatment Regulations) at 40 C.F.R. Part 403. These pretreatment standards are applicable to any user of a POTW, defined as a source of an indirect discharge. 40 C.F.R. 403.3(h). These national pretreatment standards include: 1) a general prohibition and 2) specific prohibitions. 40 C.F.R. 403.5.(a)(1) and (b). The general prohibition prohibits any user of a POTW to introduce a pollutant into the POTW that will cause pass through or interference. The regulations define both pass through and interference. Section 307(d) of the Act prohibits discharge in violation of any pretreatment standard. 33 U.S.C. § 1317(d).

On October 20, 2011, EPA announced that it will develop effluent guidelines for discharge of wastewater from the coalbed methane extraction industry and will develop pretreatment requirements for discharges of wastewater from the shale gas extraction industry. To ensure that these wastewaters receive proper treatment and can be properly handled by treatment plants, EPA will gather data, consult with stakeholders, including ongoing consultation with industry, and solicit public comment on a proposed rule for coalbed methane in 2013 and a proposed rule for shale gas in 2014.

2. ***The Chesapeake Bay Foundation and a number of other petitioners recently filed a citizen petition requesting the completion of a programmatic environmental impact statement addressing the cumulative impacts of drilling in the Marcellus Shale formation. Given the dramatic expansion of drilling activity in the Marcellus Shale region, the potential impacts on water resources, air quality, management of hazardous chemicals, forest fragmentation, and extensive socio-economic impacts, does EPA support the petitioners' request?***

Response:

EPA is aware of the concerns raised by the Chesapeake Bay Foundation and other stakeholders regarding the potential impacts associated with natural gas hydraulic fracturing in the Marcellus Shale formation. We are working with the other federal agencies, which also received the petition, to carefully consider the matter and expect to respond to the petition within a reasonable time.

3. ***The House Committee on Energy and Commerce undertook a study of hydraulic fracturing that revealed that twelve drilling service companies had injected underground over 32 million gallons of fluids containing diesel fuels from 2005-2009. The results of this investigation were disclosed in a letter to EPA Administrator Jackson. Can EPA verify the accuracy of these figures? What additional investigation into these allegations is EPA conducting?***

Response:

The figures used in the House Committee on Energy and Commerce investigation come directly from the service companies themselves. The House investigation is based on only those companies who cooperated with the House request for information regarding chemicals used in hydraulic fracturing activities. Because data submitted to the House Committee is considered proprietary information, EPA is not legally able to view the information in order to verify it.

However, EPA has gathered data on fracturing fluids from nine service companies as part of the study we are conducting on the potential relationship between hydraulic fracturing and drinking water resources. Three of these companies are the same as in the House investigation (BJ Services, Halliburton, and Schlumberger), and EPA is reviewing those data at this time. However, we are unable to independently verify the quantities reported by the House Committee on Energy and Commerce due to the nature of the information provided by the Committee. EPA requested data from BJ Services, Complete Production Services, Halliburton, Key Energy Services, Patterson-UTI, RPC, Inc., Schlumberger, Superior Well Services, and Weatherford.

4. In response to questions from Senator Udall, you stated that the use of diesel-containing fracking fluids without a Safe Drinking Water Act permit would constitute a violation of the Act. How many cases of such activities has EPA become aware of? What legal actions are the Agency or its delegated authorities taking in each instance?

Response:

Based on information described in an October 25 letter to EPA Administrator Lisa P. Jackson from Reps. Waxman, Markey, and DeGette, EPA is aware that a number of oil and gas service companies collectively injected 32.7 million gallons of diesel fuels and fluids containing diesel fuels into wells between 2005 and 2009. EPA will evaluate on a case-by-case basis any potential violations from the injection of diesel fuels into wells and the disposal of wastewater that it discovers, including whether to initiate follow-up enforcement action.

Senator James M. Inhofe

1. ***In House Report 111-316, EPA was tasked with doing a hydraulic fracturing study:***

- ***1a. EPA's initial plan was to look at many other aspects of hydraulic fracturing, such as air impacts and environmental justice, in addition to "the relationship between hydraulic fracturing and drinking water." In light of what will probably be increasing timing and budget concerns, what steps will EPA take to maintain its focus on the Congressional request so that the American people get the most accurate and valid data in an expedient fashion?***

Response:

The research that will be conducted pursuant to the final study plan focuses on the potential impacts of hydraulic fracturing on drinking water resources, which is consistent with the Congressional request. Areas of research such as air impacts and ecosystem impacts are considered to be outside the scope of the current study. Ensuring that all Americans have access to a clean and safe environment, including safe drinking water, is an EPA-wide priority. As such, the final study plan emphasizes research to identify the factors that may contribute to impacts, if any, on drinking water resources in communities across the nation. In this context, the plan proposes an initial assessment to determine the extent to which hydraulic fracturing occurs in minority, low income, and indigenous communities. EPA incorporated the advice of its Science Advisory Board into the final study plan to be sure the study will address the highest priority potential public health and environmental concerns.

- ***1b. Will there be a section in the study putting the environmental and public health risk profile identified by EPA into the current state and federal regulatory context, including guidance and other requirements used to regulate the industry? If so, please explain how.***

Response:

This study will not evaluate the efficacy of the existing regulatory framework because EPA considers this to be outside of Congress's request. The goal of EPA's study is to examine the conditions that may be associated with the potential contamination of drinking water resources, and to identify the factors that may lead to human exposure and risks. While the study will evaluate existing data on the efficacy of existing treatment technologies, it will not focus on existing regulatory requirements applicable to hydraulic fracturing operations or specific opportunities for future regulation.

- ***1c. One area EPA has indicated it will be focusing on—water use—is outside of the scope of the authorizing language. Water use is largely the province of state law and has evolved over the past two hundred plus years. Water use—for any purpose—will be subject to a well-established state legal structure that defines its acquisition. Hydraulic fracturing is no exception. Water used for the fracturing process must be obtained within this system. How will the study account for, work within, and recognize state and local water use laws?***

Response:

EPA designed the study to address the lifecycle of hydraulic fracturing operations, a scope which its Science Advisory Board considered appropriate. The study will consider the use of water in hydraulic fracturing operations, from water acquisition through the mixing of chemicals and actual fracturing to the post-fracturing stage, including the management of flowback and produced water and its ultimate *treatment and/or disposal. This study will not evaluate or make recommendations related to well-established state and local water use laws or structures because EPA considers this to be outside the scope of Congress's request.*

- ***1d. What information will EPA include regarding how the gas industry's water use compares to water use by other energy sources?***

Response:
EPA's study will not compare water use by the natural gas industry to water use by other energy sectors. We plan to account for the differences in the nature of water use in hydraulic fracturing (e.g., potential return to the environment versus permanent loss in deep formations) and the related impacts on water quality (e.g., the identity, concentrations, and treatability of contaminants).

- ***1e. Our domestic natural gas industry has a wealth of experience about all aspects of hydraulic fracturing. Industry personnel necessarily have been present as thousands of gas wells have been developed. What steps will EPA take to be certain it gains the benefit of that experience?***

Response:

Stakeholders have played an important role as EPA developed its study plan and as it carries out the study. EPA involved stakeholders—including industry personnel—from the early stages in the development of the study plan and will continue to provide mechanisms for stakeholder involvement throughout the duration of the study. Prior to developing the study plan, EPA held a series of public meetings and webinars with interested stakeholders to hear their comments related to hydraulic fracturing. EPA also reviewed and considered public comments submitted to the Science Advisory Board as part of its review of the draft study plan.

EPA has also engaged experts through a series of four technical workshops on hydraulic fracturing. These workshops provided EPA researchers with an opportunity to discuss technical issues with experts from industry, academia and elsewhere. The information provided by industry and other participants at the workshops will inform the research we conduct as part of the current study.

- ***1f. Certain sources that are cited in the Draft Study Plan are from well-known environmental activist groups and are weighing in with respect to issues that will be relevant to the outcome of the EPA study. How will information or citations from advocates be used in the study in an objective manner? Will the information provided by such individuals or entities be noted in the study? If there are any references to such data, would you commit to disclosing clearly the originator's known position so that the general public will have the opportunity to evaluate objectively all information offered in the Draft?***

Response:

In the interest of transparency and objectivity, EPA will provide full, properly reported and cited references on the source of all studies, reports and data cited in our study. EPA will consider the quality of data and information in our decision to cite or otherwise rely on information. Additionally, all research products will undergo a peer review process. EPA will not seek disclosure of positions of authors or providers of data or information used by the study.

- ***1g. Does the EPA still expect to release an interim report by 2012 that focuses only on the results of the retrospective case studies and scenario evaluations?***

Response:

There is a great deal of public interest in the current study. While we realize that some of the research projects identified in the draft study plan are long-term projects, we feel that it is our responsibility to publish results as soon as possible. The 2012 report will allow us to communicate results from shorter-term projects in the proper context.

- ***1h. Does the draft plan include a process by which EPA can update its research findings as technology advances? For example, I understand that the hydraulic fracturing service industry is continuously working to improve treatments and disposal methods to reduce the environmental risk associated with produced water and flowback fluid. Best practices are being employed by a growing number of responsible fracturing companies across a broad spectrum of practices. What is EPA doing to develop a process by which it can periodically update its research findings to account for technological advances and these best practices?***

Response:

EPA is working with stakeholders to identify up-to-date information on the technology and practices used in hydraulic fracturing operations, including wastewater treatment and disposal. Consequently, the 2012 and 2014 reports will reflect the most current information available.

- ***1i. How does the Study Design Draft effectively distinguish between those issues that are fracturing related and those that exist at all natural gas and oil production activities?***

Response:

The Draft Hydraulic Fracturing Study Plan focuses on features of oil and gas production that are particular to—or closely associated with—hydraulic fracturing, and their impacts on drinking water resources. The SAB- supported this approach and specifically cautioned EPA against studying all aspects of oil and gas production, stating that the study should "emphasize human health and environmental concerns specific to, or significantly influenced by, hydraulic fracturing rather than on concerns common to all oil and gas production activities."

2. ***EPA has been studying the possibility of developing effluent limitations guidelines for the coalbed methane (CBM) extraction sector of the oil and gas industry since 2006. Based on a series of Federal Register notices and industry surveys, a decision on the CBM sector was expected as part of the final 2010 Effluent Guidelines Program Plan Report, slated for publication in December of 2010.***

2a. What is the status of the report that was due to be published in December of 2010?

Response:

EPA announced the 2010 Effluent Guidelines Plan on October 20, 2011, and a Federal Register notice was published on October 26, 2011. The final Coalbed Methane Study was also issued with the Plan and is available on our website at http://water.epa.gov/lawsregs/lawsguidance/cwa/304m/.

- ***2b. What evidence does EPA have to suggest that these Centralized Waste Treatment Point (CWTP) guidelines are insufficient to cover treatment of well site wastewaters?***

Response:

For both CBM and Shale Gas Extraction (SGE) the wastewater contains high concentrations of Total Dissolved Solids (TDS). The concentrations of TDS differ between the two sectors with SGE wastewater having very high TDS concentrations (typically over 100,000 up to 400,000 mg/L), whereas CBM wastewater reflects a broad range of TDS concentrations (<50 to 171,000 mg/L) depending on the coal formation and the location of the well within the formation.

As described in the EPA's final effluent guidelines program plan, operators may dispose of shale gas wastewater by sending it to POTWs or to private centralized waste treatment facilities (CWTs). The vast majority of POTWs employ equalization, bulk solids removal, biological treatment, and disinfection. POTWs are likely effective in treating only some of the pollutants in shale gas wastewater, such as the conventional and organic pollutants. These treatment technologies are not designed to treat high levels of TDS, naturally occurring radioactive material (NORM), or high levels of metals[1]*; it is believed that much of these pollutants pass through the POTW untreated. Many CWTs, of which 90% discharge to POTWs, are similarly not designed to treat for high TDS or NORM.*

- ***2c. EPA currently regulates industrial effluent to CWTP. The guidelines are broadly applicable to numerous industries, including ELG activities, and account for the constituents that EPA is most concerned about controlling. Has there been a finding that these regulations are ineffective? If so, where is the finding?***

Response:

The Agency has not issued a finding about the effectiveness or lack thereof of the CWT effluent guidelines. See previous response for an explanation of our basis for initiating rule makings related to CBM and SGE wastewaters.

- ***2d. How does adding this regulation comply with the President's January 18th, 2011 Executive Order? Will EPA be coordinating with the Whitehouse or CEQ to justify the singling out of the ELG industry for duplicative regulation?***

Response:

EPA intends to fully comply with E.O. 13563 as it proceeds to develop effluent limitations guidelines for these industry sectors. No comprehensive set of national standards exists at this time for the disposal of wastewater discharged from natural gas extraction activities. To ensure that these wastewaters receive proper treatment and can be properly handled by treatment plants, EPA will gather data, consult with stakeholders, including ongoing consultation with industry, and solicit public comment on a proposed rule for coalbed methane in 2013 and a proposed rule for shale gas in 2014. The final standards will undergo interagency review pursuant to EOs 13563 and 12866 before being finalized.

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[1] Metcalf & Eddy Inc. (2003) Wastewater Engineering: Treatment and Reuse McGraw-Hill, New York.

- ***2e. What less burdensome alternatives is EPA exploring to achieve the performance objective?***

Response:

As EPA develops ELGs for these industry sectors, EPA plans to gather data from industry and use that data to develop appropriate technology options. EPA typically identifies a range of options and selects an option based on statutory criteria and other relevant factors, including industry affordability.

- ***2f. Will there be a qualitative and quantitative cost benefit analysis on which the public can comment?***

Response:

As parts of our ELG development efforts, we plan to evaluate the environmental impacts associated with the wastewater discharges from the two industries. In addition, EPA will assess the costs of various regulatory options, the financial impacts of these costs on the industry, and expected benefits. The proposed rule will include a summary of the environmental assessment, including qualitative and quantitative aspects, and will provide an opportunity for public comment. If the proposed requirements are considered significant as defined under E.O. 12866, the Agency will also estimate the monetized value of the environmental benefits.

- ***2g. How has EPA coordinated with the regulated community?***

Response:

EPA began its study of CBM in 2006. Early in the study EPA held several meetings in the CBM producing basins so that we could meet as many industry representatives as possible and visit a number of production sites to observe practices. Additionally, EPA held conference calls and meetings with industry representatives throughout the course of the study. Over the coming months, EPA will begin the process of developing a proposed standard for the CBM and SGE sectors with the input of stakeholders, including industry and public health groups.

- ***2h. Given the regulatory programs already in place, why does EPA feel the need for more regulation? Is there a regulatory gap the Agency has identified? If so, where is the gap and what is the evidence to support the existence of an alleged gap? Is the Agency simply basing its analysis on a few anecdotes?***

Response:

As described in the EPA's final 2010 Effluent Guidelines Program Plan, what we know is that shale gas extraction generates extremely large volumes of wastewater that contain considerable pollutant loads. Some of this is being responsibly reinjected into appropriate underground wells; other volumes of wastewater may not be treated effectively by existing treatment facilities. Resulting discharges have the potential to affect both drinking water supplies and aquatic life. These concerns and issues will not dissipate as shale gas production is expected to increase. As a result, EPA has decided to initiate rulemaking to decide the appropriate level of pretreatment standards for this industry. Also see the response to Question 2b above for an explanation of our basis for initiating rule makings related to CBM and SGE wastewaters.

3. Please clarify the statement that you made at our hearing that oil and gas drillers who injected diesel fuel during hydraulic fracturing without a permit broke the law.

Response:

Under the Safe Drinking Water Act (SDWA), any underground injection which is not authorized by permit (or in some cases, by rule) is prohibited. In the Energy Policy Act of 2005, Congress amended the SDWA definition of "underground injection" to exclude hydraulic fracturing related to oil, gas, or geothermal production activities, except for when diesel fuels are used. Therefore, an underground injection control permit is required for the injection of diesel fuels during hydraulic fracturing related to oil, gas, or geothermal production activities, and any unauthorized injection of diesel fuels was in violation of the law.

Senator David Vitter

In testimony before our Committee, Deputy Administrator Perciasepe asserted that "using diesel fluids for hydraulic fracturing in shale... is subject to the Safe Drinking Water Act" and that operators would be required to have a permit in order to do so, indicating that not doing so would be a violation of the law. Given the assertions he made, the agency presumably has done a rigorous analysis of the law and has developed a new legal theory that would explain why operators now apparently must obtain a permit even though the agency in the past took a different position. To help us better understand the agency's position and so that the hearing record is complete, we ask that you answer the following questions:

1. ***What was EPA's basis for concluding that wells being hydraulically fractured with fluids containing diesel fuel should be considered to be Class II wells under EPA's VIC regulatory scheme given the Agency's prior consistent position that "EPA's Class II regulations were not designed to, and do not specifically address the unique technical and temporal attributes of hydraulic fracturing," and that it was "not entirely appropriate to ascribe Class II status" to wells being hydraulically fractured?***

Response:

Class II wells receive fluids

- *Which are brought to the surface in connection with natural gas storage operations or conventional oil or natural gas production and may be commingled with waste waters from gas plants which are an integral part of production operations, unless those waters are classified as a hazardous waste at the time of injection*
- *For enhanced recovery of oil or natural gas; and*
- *For storage of hydrocarbons which are liquid at standards temperature and pressure. (40 CFR § 144.6(b))*

In 1997, the Eleventh Circuit Court of Appeals established that hydraulic fracturing is "underground injection" for the purposes of regulation under the SDWA. Legal Environmental Assistance Foundation, Inc. v. EPA, 118 F.3d 1467 (11th Cir. 1997) (LEAF I). The same court later established that wells used for the injection of hydraulic fracturing fluids must be regulated as Class II wells under the UIC program. Legal Environmental Assistance Foundation, Inc. v. EPA, 276 F.3d 1253 (11th Cir. 2001) (LEAF II). The court held that EPA must classify hydraulic fracturing as one of the five existing well classes and that "wells used for the injection of hydraulic fracturing fluids fit squarely within the definition of Class II wells" used for enhanced recovery of oil or natural gas.

SDWA § 1421(d)(1), as amended by the Energy Policy Act, excludes the "underground injection of fluids or propping agents (other than diesel fuels) pursuant to hydraulic fracturing operations related to oil, gas, or geothermal production activities" from UIC regulation. Therefore, hydraulic fracturing using diesel fuels is subject to UIC regulation under 40 CFR § 144 and 146. By requiring a permit for hydraulic fracturing using diesel fuels, EPA is following the intent of the Congressional amendment to the SDWA through the Energy Policy Act of 2005.

2. ***What communications, if any, did EPA have with third parties regarding the regulation of hydraulic fracturing activities involving diesel fuel use under the SDWA prior to posting the statements on its website?***

Response:

While EPA has had many conversations with stakeholders about hydraulic fracturing activities since 2005, there was no specific outreach to third parties prior to posting the statement on the website.

3. ***In posting these statements on its website, how did EPA intend to address the problems previously identified by the Agency in applying the Class II VIC regulations to hydraulic fracturing operations in light of the key differences between hydraulic fracturing and typical VIC operations recognized by EPA, such as the "extremely limited" duration of hydraulic fracturing operations and the fact that hydraulic fracturing is "ancillary" to an oil and gas well's principal function of producing oil and gas?***

Response:

EPA is currently in the process of developing guidance to address issues regarding the application of Class II UIC regulations to hydraulic fracturing with diesel fuels.

4. ***What consideration, if any, did EPA give to the potential impact of its statements on the position set forth on EPA's website that oil and gas production wells are not regulated by the VIC program?***

Response:

The Safe Drinking Water Act as amended by the Energy Policy Act of 2005 states that

> *"The term 'underground injection' –*
> *(A) means the subsurface emplacement of fluids by well injection; and*
> *(B) excludes –*
> *(i) the underground injection of natural gas for purposes of storage; and*
> *(ii) the underground injection of fluids or propping agents (other than diesel fuels) pursuant to hydraulic fracturing operations related to oil, gas, or geothermal production activities."*

The statement on the website was information restating a longstanding, established interpretation of the statute.

5. ***What efforts, if any, did EPA make to communicate with states having primacy over the Class II program regarding its decision either before or after posting the statements on its website?***

Response:

Because the website reflects existing law and regulations EPA did not believe that consultation with primacy states was necessary. See answer to 2.

6. ***What efforts, if any, did EPA make to inform the regulated community about the Agency's action either before or after posting the statements on its website?***

Response:

Because the website reflects existing law and regulations EPA did not believe that consultation with the regulated community was necessary. See answer to 2.

7. ***Does EPA have any objective, documented evidence of the contamination of drinking water supplies as a result of the use of diesel fuel in hydraulic fracturing fluids anywhere in the United States and, if so, could you please share it with the Committee?***

Response:

EPA is currently investigating instances of alleged drinking water contamination in various localities in the U.S. To protect the confidentiality of potential case developments and assure effective enforcement, EPA cannot comment on potential enforcement investigations or responses. It is important to remember that the SDWA requires EPA to take preventative measures to protect underground sources of drinking water. The study EPA is conducting pursuant to House Report 111-316 on the potential impacts of hydraulic fracturing on drinking water resources will provide further insights into this question.

Senator CARDIN. Mr. Perciasepe, first of all, thank you very much for your testimony. I agree with the point that you make that there are significant environmental laws that give EPA authority to act in this area.

I want to just start by I think there is general agreement in this committee and in Congress. We want to be able to tap into the natural gas reserves in this Nation. We believe that is an energy source that we have. We want to be able to obtain that energy source and we want to do it in a safe and environmentally sound manner.

But as you point out, you have certain responsibilities under environmental laws that you are responsible to enforce. I listened to Senator Inhofe talk about how the fracking practice works so far underground, and we all understand that. You inject fluids that contain certain chemicals. Those fluids then are extracted, and when they are extracted they bring out not only the original fluids, but they bring out a whole host of potential pollutants that could be very damaging to public health.

The question is: What then happens to that fluid that is removed during the fracking procedures? As I understand it, the best practice that many of the gas companies use is to recycle that fluid. That is fine. They recycle it. They take out the hard chemicals that they can, the pollutants, and dispose of them properly, and then we use the fluid in a way that is constructive to getting more natural gas.

In some cases, they inject the fluids back into the earth in underground wells. That is also cases have been done in a very sound environmental way. But in some cases, they take it to the wastewater treatment facility plant that is close by, which to me presents significant problems. Let me just cite a letter that was sent by EPA, the Regional Administrator Shawn Garvin, to the Pennsylvania Department of Environmental Protection, where the EPA said wastewater resulting from gas drilling operations contained material that may present a threat to human health and aquatic environments. Many of these substances are not completely removed by wastewater treatment facilities and their discharges may cause or contribute to impaired drinking water quality from downstream users or harm aquatic life.

Well, it seems to me that you have the responsibility to make sure that the wastewater treatment facilities are in fact complying with the permit. If you believe there is a danger to the public health because of the inability to remove certain pollutants, you need to take action. My question is: Has the EPA taken action? If not, why not?

Mr. PERCIASEPE. Thank you for that question. There are a number of factors that would be involved with how we would take action when these fluids are used in a publicly owned treatment works, to do that as a general statement. There needs to be care-taken that the pollutants won't go through the sewage treatment plant or that they won't disrupt the sewage treatment plant's operation.

In the case that you cited in Pennsylvania, the Regional Administrator has been working with the State. We have issued in the past information collection requests so that we could understand what was going on to those different sewage treatment plants. In many cases, those sewage treatment plants have stopped taking some of those fracking fluids and produce water.

So we are in the process of working with Pennsylvania. Pennsylvania has responded to that letter that the Regional Administrator sent, and we feel like we are making good progress there.

Senator CARDIN. We appreciate that. Some of us think this is a pretty clear issue and that there needs to be pretty definitive action by EPA so that we can avoid this public health risk.

There are other areas that you could be enforcing the environmental laws. As you know, there is no exemption if diesel is used in the fracking process. Yet I am not aware of any enforcement actions taken by EPA in that regard. Am I wrong? Have there been enforcement actions taken against fracking privileges that endanger our environment?

Mr. PERCIASEPE. We have taken enforcement actions through issuing orders where we think there is an imminent and substantial endangerment. But in terms of enforcement where there may be diesel fuel being used for fracking, we are in the process of collecting information on that. We have information from Congress, as well as our own information collection we have been doing. That is in the process of going through enforcement procedures.

Senator CARDIN. Let me yield to Senator Inhofe. I might have some questions after my colleagues have completed.

Senator INHOFE. Thank you, Mr. Chairman.

In response to Senator Casey and his FRAC Act, I do want to point out that there are other points of view within Pennsylvania regarding the need for Federal intervention in the regulation of hydraulic fracturing.

First of all, to submit testimony for the record from Michael Krancer, who is the Secretary of Pennsylvania's Department of Environmental Protection. Senator Casey may not realize it, but according to Secretary Krancer, Pennsylvania already requires the disclosure of frack fluids. As he pointed out, "The State DEP's new regulations require operators to disclose the chemical additives and the hazardous constituents of those additives on a well by well basis." This is the DEQ from the State of Pennsylvania.

He went on to say, "Simply put, because of a long history of oil and gas development and comprehensive regulatory structure, Pennsylvania does not need Federal intervention to ensure an appropriate balance between resource development and environmental protection."

I would also like to highlight and submit for the record two studies from Penn State University examining the economic impacts of the current activity in Pennsylvania's portion of the Marcellus. The studies found that Marcellus activity, "generated $3.9 billion in value-added; $389 million in State and local tax revenues and more than 44,000 jobs. By 2020, employment would expand by 200,000 jobs and annual gains in State and local revenues would exceed $1 billion."

Additionally, Penn State University also concluded that Federal regulation, just like Senator Casey's FRAC Act, was a serious threat to Marcellus development: "Proposals to regulate hydraulic fracturing under the Safe Drinking Water Act pose yet another serious threat to the development of the Marcellus Shale and other unconventional gas sources."

I would like to submit testimony also from Mike Paque who is from the Groundwater Protection Council. That is a national association of State groundwater and underground injection control agencies whose mission is to promote the protection and conservation of groundwater. That is what they do for a living.

Their testimony describes the new frack-focused registry which went active just yesterday. Frack Focus provides for a detailed and thorough disclosure of all frack fluid constituents on a well by well basis, and even though participation at this time is voluntary, he points out, "within the first 8 hours of going live, Fracfocus.org had 24 oil and gas companies signed on to use it and nine already uploading fracturing data on 309 wells."

A quick glance at the list of participating companies revealed that the largest companies, really the largest companies and small companies, are clamoring for this opportunity and they are participating.

Now, clearly the States are running successful regulatory programs. We are going to hear from some of them today and I would hope, Director Perciasepe, that you would be able to stick around and listen to some of their testimony.

On the Federal level, of course, EPA is doing a study on the impacts of hydraulic fracturing. I also understand that President Obama has asked the Department of Energy's Advisory Board to look into fracking. On top of that, the White House Council of Environmental Quality has been petitioned to study any cumulative impacts.

I would say, Mr. Perciasepe, to help me understand these various studies and particularly how they all fit together, it would be helpful if you could commit to brief my staff on the efforts on maybe a quarterly basis. You have always been willing to do that in the past, and I am sure you would do that. That way, we can properly see what this oversight is doing.

Now, just one thing. I was going to hold this up, by the way, and I am sorry I didn't. This is the Marcellus Shale. This is what we are talking about. This is how they have to get the gas out of this type of formation and the only way they can do it is fracking.

So I would say that States are different. In my State of Oklahoma, the Anadarko Shale, we are talking about 30,000 feet. Go just north in Kansas, their shale is between 3,000 to 4,000 feet. Louisiana is something like three miles deep; Pennsylvania, two miles deep. So it is different.

That is why the one-size-fits-all just doesn't really work in this case. So the question I would ask you is, are they not doing a good job in the States?

Mr. PERCIASEPE. There are many States taking leadership on this issue and they obviously, as I mention in my oral testimony, are on the front lines on the Safe Drinking Water Act and the Clean Water Act where they have authority. But let me just go back to the Pennsylvania example for just a minute that you started with, Senator.

When the fracking fluids and the produced water were being brought to the publicly owned treatment works, the responsibility for the discharge permit of that sewage treatment plant is the State's, and the State's discharge permit did not contain limits on some of the material that were in the fluids that were going to the sewage treatment plant. It is that kind of back and forth of oversight between EPA and the State that I think is important to make sure that we have a level playing field.

But you are correct, there is no one-size-fits-all here. The geology in all of these different shale formations around the country is different. There are different depths. There are different layers above them in the sedimentary rock levels. So we have to be able to look at those things in that way.

So our primary role here is oversight of State programs where they are running the programs, providing guidance where we can, and where we see some imminent endangerment, we may take our own action on that.

Senator INHOFE. My time is expired, but I would only say that once you start from the Federal level, it grows. That is my concern.

I say to my friend Senator Boozman, he wasn't here during my opening statement, I listed a lot of the States, including your State of Arkansas, that has a lot of these reserves, and I am just really concerned over the over-regulation, but we will hear that from some of the State people in the next panel.

Thank you very much.

Senator CARDIN. Senator Boxer?

Senator BOXER. Yes. I hear what my colleague is saying about his preference for State regulation. I would cite an example, though, of New York just shutting it down for the moment because they are concerned. I think since Senator Casey's name was mentioned by my colleague, he wasn't here to explain what he meant, but what I heard him say is that his State constitution calls for defending the quality or more. They make it a right there to clean water and clean air. So if the State next door doesn't have the same type of laws, what happens is that his State could be impacted.

I don't have a particular position on where we go from here except that I think we need to have the facts. I think that is the point, and I want to ask you about this.

Will EPA's study look broadly at all potential impacts to drinking water, including impacts from wastewater that is producing during the hydraulic fracturing process, in your studies?

Mr. PERCIASEPE. Senator, we are characterizing both the fracking fluids. We have gotten information from the companies. We are also going to be characterizing the produced water because the fracking fluids don't, for instance, contain radionuclides. These are naturally occurring in some of the rock formations, but they come out with some of the produced water.

Senator BOXER. So the answer is yes, you are looking at this?

Mr. PERCIASEPE. Yes.

Senator BOXER. OK. Can you assure us that EPA will use an independent, comprehensive and scientific process to provide an accurate and unbiased assessment which will help us make sure drilling is done safely and responsibly and protect the public health?

Mr. PERCIASEPE. Yes. Not only will the study plan be peer-reviewed before we even start the study, but the actual results of the study will be peer-reviewed as well.

Senator BOXER. I want to ask a question about diesel fuel here. On January 31, a number of Representatives in the House sent Administrator Jackson a letter providing the results of an investigation which found that diesel fuel continues to be used in hydraulic fracturing. First of all, to your knowledge, is that true?

As you know, the Safe Drinking Water Act exemption for hydraulic fracturing specifically does not include the use of diesel fuel, so you still have the ability to regulate that, is my understanding.

In 2003, EPA signed an MOU with major drilling service companies to eliminate the use of diesel in hydraulic fracturing operations. Will you provide us with an update on what efforts EPA has taken to protect public health from the use of diesel fuel in hydraulic fracturing?

Mr. PERCIASEPE. The MOU or MOA, I think it was, with the companies that was developed was for hydraulic fracking in coalbed methane production, not in the shale production.

Senator BOXER. OK.

Mr. PERCIASEPE. So that is where there was a concern because many of those formations are at a shallower depth.

We are in the process of confirming and reviewing the information that we received from Congress. We have our own information requests out to the companies and we are looking at that as well.

Senator BOXER. OK. As a lot of us have mentioned, millions of gallons of wastewater produced during the hydraulic fracturing process can contain radioactive elements, corrosive salts, carcinogens. These reports indicate wastewater is being sent to municipal wastewater treatment plants that may not be equipped to treat this waste, which could result in a discharge of harmful toxins to local waterways.

What authorities does EPA now have to address the treatment of wastewater from natural gas drilling operations?

Mr. PERCIASEPE. There are several steps that have to be taken in terms of the use of a publicly owned treatment works for disposal of the fluids. The first are that limits have to be placed on the permit for the sewage treatment plant. Now, if the State is the agency that is running the NPDES pollution program in that State, then they need to put those limits on those plants. If the State is operating the pre-treatment program, which would be how you treat these fluids before they go into the sewage treatment plant, they would be required to do that.

EPA is looking into guidance on what pre-treatment might be useful for those kinds of waste, but the first step would be obviously making sure we have the right limits on every plant that is going to be receiving those wastes. That is part of our oversight responsibility.

Senator BOXER. So you do have that oversight responsibility right now?

Mr. PERCIASEPE. Yes.

Senator BOXER. Are you working with municipal wastewater treatment plants that accept hydraulic fracturing waste to ensure that adequate treatment is occurring? Are you working with the plants themselves at this time?

Mr. PERCIASEPE. Where the States are the permitting authority, we are working with the States, like we are doing in Pennsylvania.

Senator BOXER. OK. Well, I will submit the rest of my questions for the record.

Thank you, Mr. Chairman.

Senator CARDIN. Senator Boozman.

STATEMENT OF HON. JOHN BOOZMAN, U.S. SENATOR FROM THE STATE OF ARKANSAS

Senator BOOZMAN. Thank you, Mr. Chairman. Again, I thank you and the Ranking Member for having this hearing. It is very, very important. It is very important to my State and really just in the Nation in general in the sense that we certainly need the resources that it engenders.

Now, currently as it stands, the gas and oil industry is regulated by the States as far as these type of things?

Mr. PERCIASEPE. The States have been delegated the authority under the Clean Water Act or the Safe Drinking Water Act. They are the ones that have primacy or the delegated authority. EPA provides oversight of those States. I just went through an example of what that oversight might look like in a particular place. So that is in my written testimony also, Senator, the detail of all those interactions.

But it is like almost all the other pollution laws that we have, an interaction between the States and the Federal Government with the Federal Government providing oversight and delegation of authority.

Senator BOOZMAN. Well, I think it is important as we have new technology, and certainly this is a new technology that hasn't been around very long and is a very effective technology, that we understand potential risks and deal with them, and deal with them in a sound way.

I guess my feeling is that the Agency has the responsibility of providing good science to help the States in making their decisions. But I feel very strongly that it does need to remain at the State level. In the past, the oil industry has worked fairly well in doing that. I think that there is a good record. So again, I would be inclined to continue as we are now, again with the EPA providing sound science.

When you do the studies and things, how do you make it such that there is an apartness? Will you be the ones that are selecting the people that do the study and the peer-review board? I guess what I am trying to see is what separation there is in that regard.

Mr. PERCIASEPE. We have a Science Advisory Board that EPA uses for many of its peer-review, not all, but many of its peer-review——

Senator BOOZMAN. The Science Advisory Board, is that appointed by the EPA?

Mr. PERCIASEPE. Yes. It is an independent Federal advisory committee and it provides advice to the Administrator on science matters that we present to it. They can set up special panels if they need the expertise to look at a particular subject. They operate in many ways similar to the way the National Academy of Sciences would set up a panel to look at a particular matter, of scientists in that field.

Senator BOOZMAN. OK. Thank you very much for your testimony.

Senator CARDIN. Senator Lautenberg.

STATEMENT OF HON. FRANK R. LAUTENBERG, U.S. SENATOR FROM THE STATE OF NEW JERSEY

Senator LAUTENBERG. Thanks, Mr. Chairman.

Few things in life are more essential than the water we drink, and government has few responsibilities as critical as protecting our country's water supply. I am going to use these couple of minutes, Mr. Chairman, to make my statement.

But communities across the country are reporting serious contamination of their water supplies from a drilling process that we are now looking at, fracking. And the Environmental Protection Agency, as we have discussed here and widely know, has been powerless to protect these communities because a Republican Congress at Vice President Cheney's behest, prohibited EPA from setting standards.

This so-called Halliburton loophole eliminates the Federal oversight that we would like to see of companies that inject chemicals into the ground in order to get to the hard to reach natural gas. Some States, which we have heard, have adopted strong laws to restrict fracking, reducing the risk to their residents.

But let's face it: water doesn't recognize State boundaries, and you may live in a State that has strong laws, but if the State next door doesn't, your water and your families could still be at risk. The risk to humans isn't limited to those who live near the drilling sites, and during the fracking process, the wastewater that flows to the surface can also be highly contaminated.

A recent *New York Times* investigation revealed that this wastewater can end up in rivers and streams, and even if it is taken to a wastewater treatment plant, the water often contains radioactive and toxic materials that the treatment facilities cannot remove.

We don't want to make any mistakes in our representation here. Natural gas has its advantages and it is critical for our energy needs. Natural gas is cheaper, cleaner than coal or oil, and an important domestic energy source for our country.

But nothing, nothing is more important than the health of our children and risking their health is an unacceptable price under any condition. We simply can't allow their drinking water or our rivers and streams to be contaminated by natural gas drilling. We need the cleaner fuels to replace dirty coal and oil, but we can't allow the cure to be worse than the disease.

That is why I have joined with Senator Casey and others on this committee to introduce a bill to close the Halliburton loophole and restore EPA's ability to regulate fracking. Our bill would also require companies to disclose the chemicals they use in the process.

Now, 25 years ago, I authored the right-to-know law on toxic chemical releases in the air to make sure that people know about potential hazardous substances in their communities. Parents have a right to know what is in the fracking fluid that can contaminate the water their children drink, and more information on contaminants, which we are happy to see EPA undertaking, will empower citizens and help the government to make better decisions on pollutants in the water supply. We need the natural gas, but we also need clean water.

So I look forward to hearing from our witnesses about how we can work together to ensure natural gas is done as safely as possible.

Senator LAUTENBERG. Now, I want to ask you, Mr. Perciasepe, a question about our air in New Jersey is already dirty by coal-fired powerplants to the west of us, and now there are unprecedented numbers of hydraulic fracturing wells in Pennsylvania and other nearby States. What can we expect with air pollution coming into New Jersey from these activities?

Mr. PERCIASEPE. The air emissions from oil and gas activities would be regulated under the Clean Air Act, depending on the size and the type of emission that it is. There have been problems with some areas of the country where some of the emissions from all the activities going on related to natural gas extraction that it has created an increase in emissions of volatile organic compounds or nitrogen oxides which has contributed to ozone. So it is certainly something that would have to be carefully looked at, and there is authority under the Clean Air Act to do that.

Senator LAUTENBERG. So that is the conclusion that you come to at EPA, when will we be able to find out what is happening and what we can do to prevent it from coming all over New Jersey?

Mr. PERCIASEPE. Well, the Clean Air Act requires technology to be used, and this is a process that EPA is continually looking at in terms of how it goes about working with the States and with the industry directly on those standards that would be used.

One of the things that I mentioned in my opening comments was the President has asked the Department of Energy; the Department of Interior, who has responsibilities on public land, and EPA, who has all the regulatory oversight responsibilities, to work together with industry to find the best practices.

Certainly, one of the things we want to make sure we are looking at is, what is the best practice to be used to minimize the air impacts of the actual practice of gas extraction. On the other side of the coin is the big advantage to air pollution of using natural gas for energy production in the United States.

So we have to be able to make sure that we balance that out properly in the long-term air quality plans for the country.

Senator LAUTENBERG. Thanks, Mr. Chairman.

Senator CARDIN. Senator Udall?

Senator UDALL. Thank you, Mr. Chairman, and thanks for holding this hearing.

I would ask unanimous consent to put my opening statement in the record.

Senator CARDIN. Without objection, the statement will be included.

Senator UDALL. Thank you. Mr. Perciasepe, in 2005, the Energy Policy Act included an exemption for hydraulic fracturing from underground injection control permits under the Safe Water Drinking Act. However, there was also an exemption from the exemption, as you are well aware, for the hydraulic fracturing with diesel fuel, meaning that if you injected hydraulic fracturing fluid with diesel in it, the statutory exemption did not apply.

Recently, a House Committee report found that millions of gallons of diesel had been injected since 2005, including hundreds of thousands of gallons in New Mexico. What is EPA's position on this? Do you need a Federal permit to inject diesel fuel underground in a hydraulic fracturing operation? If not, please explain the court rulings, *LEAF* v. *EPA*, that came out in 1997, and the 2005 exemption for diesel.

Mr. PERCIASEPE. Hydraulic fracturing using diesel fuel for the fluid is subject to the Safe Drinking Water Act requirements.

Senator UDALL. That is under the court ruling, correct?

Mr. PERCIASEPE. Well, it is the plain reading of the law, the 2005 law that you just referred to. We have the information that we received from the Congress and we also are in the process of gathering our own information as we are going through our analysis. So we are looking into this issue of diesel use and we will be following up on it soon.

Senator UDALL. Yes, but my very specific question here, in a sense it is a legal question, do you need a permit to inject diesel fuel? What is the EPA's position on that specific question?

Mr. PERCIASEPE. Well, where a State has primacy, and I actually have a letter. The State of Texas Railroad Commission that Senator Inhofe mentioned earlier, has actually issued a letter inside the State of Texas saying that they can't use diesel fuel without getting a permit from them.

Senator UDALL. Well, that is the Texas situation.

Mr. PERCIASEPE. Well, it is the same law for the whole country.

Senator UDALL. If States aren't doing what Texas is doing, then are you requiring a permit?

Mr. PERCIASEPE. Well, that is what we are trying to find out and try to gather the information on where diesel fluids maybe being used. We have the information that was given to us. We are also getting information from the companies now.

Senator UDALL. So the answer to the legal question, do you need a permit to inject diesel fuel, you are not giving an answer to that today.

Mr. PERCIASEPE. Yes, I just said it is subject to the Safe Drinking Water Act.

Senator UDALL. But if the State isn't requiring a permit, are you requiring a permit on folks?

Mr. PERCIASEPE. Well, we have to find out where, and that is our investigation that is going on now. Where are these fluids being used? We have to know where it is being used to require the permit.

Senator UDALL. OK. Let me go on to something else.

Mr. PERCIASEPE. Let me be clear.

Senator UDALL. Yes.

Mr. PERCIASEPE. Using diesel fluids for hydraulic fracturing in shale is subject to the Safe Drinking Water Act. It would be required to get a permit.

Senator CARDIN. Will the gentleman yield for one moment so I can get the facts straight on this one issue?

Senator UDALL. You are taking the Chairman's time.

Senator CARDIN. I will give you an extra minute.

Senator UDALL. OK.

Senator CARDIN. According to our information, I think there is somewhere around 19 States that are using diesel as part of their injection process, and that between 2005 and 2009, there were 32 million gallons of injection fluids used that contained diesel. I would appreciate it if you could verify that for us. I think Senator Udall's point that it appears that permits are needed and we haven't seen any enforcement of this by EPA.

I thank the gentleman for yielding, but I want to make sure we get the right numbers. You mentioned hundreds of thousands. We have 32 million gallons that were used that included diesel.

Senator UDALL. Maybe asking it another way. If they didn't get a permit, they were in violation of the law.

Mr. PERCIASEPE. Yes.

Senator UDALL. OK, good. Now moving on here, in the Marcellus Shale, much of the produced water is not disposed of by injection wells, as you are aware, but rather is transported to wastewater treatment plants, many of them municipal, and then treated and discharged into waterways.

Here I am trying to get at best practices. Is this better or worse than disposing the produced water in underground injection?

Mr. PERCIASEPE. An underground injection well for disposal is going to be permitted to deal with those issues. The problem we have in many places, although I don't want to say this is everywhere, is that the discharge limits on the actual sewage treatment plant, the limits it has for discharge into the water that it is permitted to discharge into, may not have the limits on it for the chemical constituents that might be in the fluids that are going into the plant to be treated. So there would be no way to know if it is meeting those limits before it is discharged to the water.

Now, I am not saying that is the case everyplace, but many publicly owned sewage treatment plants have not put limits on their discharge to deal with the constituents of the fracking fluids or of the produced water. That is the issue we are working on in Pennsylvania, for instance.

Senator UDALL. So you are seeing that as a problem, it sounds like. If they don't adjust their wastewater treatment plants to deal with what is coming in, which isn't like municipal sewage, it is much different in terms of the constituents, that that could be a real problem and you are trying to get on top of that.

Mr. PERCIASEPE. Either putting limits on the plant then figuring out how the plant handles it, or treating the fluids before it is brought to the plant so that it can be compatible with the plant. Those are the two approaches you can take with a sewage treatment plant.

Whereas a permitted class II, I think that is right, class II underground injection control well would actually be permitted to deal with those issues.

Senator UDALL. But today, we have them just loading this produced water in trucks and driving it over to the wastewater treatment plant and then dumping it in the wastewater treatment plant. Are you aware that they are pre-treating it?

Mr. PERCIASEPE. A number of those instances where we have learned about this are ones that we are working directly with the States or gathering information under our enforcement authority under the Clean Water Act.

Senator UDALL. Thank you very much. Thank you for your service there at EPA.

Senator CARDIN. Senator Merkley.

Senator MERKLEY. Thank you, Mr. Chair.

I wanted to ask you about the article that the Cornell University researchers came out with recently that tried to look at the impact of fracking on fugitive methane, methane being a very potent global warming gas, far worse than carbon dioxide. Their initial finding was that natural gas is worse than coal in terms of its greenhouse gas footprint over a 20-year period, roughly equal to coal over a 100-year footprint, which is a real surprise to many of us.

Is this an issue that the EPA is analyzing and looking at?

Mr. PERCIASEPE. We have had a voluntary program working with companies to tighten up their system, to reduce fugitive emissions of methane, which is a natural gas. However, this study, which I don't think has actually been published yet, although obviously it has been discussed in the newspapers and the basic outlines of it are available there, is an important piece of information that we need to bring into the discussion.

If it indeed is from leakage out of the system, these are generally problems that can be addressed through proper controls or through collection controls at the wellhead. So I think it needs to be taken into account.

The other issue I mentioned earlier on clean air, the same kinds of techniques that reduce the emissions for regular criteria pollutants would also reduce the emissions of methane. This is something that is going to have to be looked at over the long haul here. We are going to have to make sure that fugitive emissions can be reduced.

Senator MERKLEY. So my understanding is that a lot of these emissions are the result of actually the fracking fluid carrying the methane to the surface and if it goes into a pone of anywhere else, that methane then gases into the atmosphere. So if it is contained in the fluid, what strategies are there that could address this?

Mr. PERCIASEPE. There are technologies that can be used when the fluids come to the surface.

Senator MERKLEY. That is what I am asking.

Mr. PERCIASEPE. There are technologies.

Senator MERKLEY. No, I am asking what technologies.

Mr. PERCIASEPE. I am not familiar with the details. They are both tightening of the system, but also collected and stripped or some other. I am not 100 percent certain on the technology. We have been working with companies in a voluntary program to do some of these, and I think I can followup with you, if it is OK, with giving you more specifics on what technologies have been tried and used. We would be very interested in sharing that with the committee, and obviously it is something that if this study, after we review it, adds to this discussion, we are going to definitely want to be looking as a country at reducing the emissions from facilities.

But in addition, we want to be looking at reducing the emissions of the criteria pollutants that are causing ozone and other problems as well. So all that can be done together in a common sense kind of way.

Senator MERKLEY. Are you familiar with the documentary Gasland?

Mr. PERCIASEPE. I am generally familiar with it, yes.

Senator MERKLEY. That was quite a dramatic demonstration. I haven't seen it. I just read the description of it. So the filmmaker runs his kitchen faucet and then holds a cigarette lighter up next to it and a ball of fire erupts because there is so much gas that it has entered into the water supply from fracking in the area. So this is obviously a pretty dramatic demonstration of the concern people have about their water supply.

Mr. PERCIASEPE. Yes, and we definitely have examples, and you have seen some, of where the drinking water supplies have been contaminated with methane itself. In those cases where we learn of this, EPA is taking enforcement actions to correct those problems or deal with those problems.

As Senator Inhofe showed earlier in his chart, which showed the shale layers being very deep, but the actual well has to go through drinking water. So if it is not properly constructed, it is conceivable and possible, and we have examples where we have seen methane contamination. How that has happened is what is the subject of some of our analysis.

Senator MERKLEY. So in that area, despite the Halliburton loophole, you feel like you have enforcement powers?

Mr. PERCIASEPE. When there is endangerment, we have enforcement powers under the Safe Drinking Water Act.

Senator MERKLEY. Thank you.

Senator CARDIN. Mr. Perciasepe, again thank you for your testimony.

Let me just point out that EPA has authority here to act in certain areas. Obviously, we think it is not adequate, then we will look at taking action, and Senator Casey has introduced legislation. But it seems to me that it is pretty clear as it relates to the wastewater treatment facility issues on the fluids that are returned to the surface.

It is my understanding there are still seven wastewater treatment facility plants taking today the fluids coming out of fracking. With your own agency already acknowledging that it presents a threat to human health, I would hope that would be at the highest priority as you look at the appropriate role for the EPA.

I think Senator Udall's point concerning the diesel issues is one also that requires EPA to take more definitive action. Senator Merkley has raised a very important issue also.

So I hope that you will respond to the urgency of some of these issues. As you have already pointed out, you have the authority. It is now your responsibility to take action.

Is there any Member seeking a second round?

Senator Inhofe, are you OK?

Senator Merkley?

Yes, sir.

Mr. PERCIASEPE. I just want to confirm what you just said, Senator, that EPA is acting on all these fronts. We are taking action where there is imminent endangerment, as we just discussed. I think if you look and step back for a minute that the dynamic between the States and the Federal Government and how we have shared our authorities under these laws for many years. Certainly, EPA's responsibility in oversight is one that we are very much pushing forward on in a very strong and strenuous way.

If I step back to my opening comment and just simply say that providing a framework that provides public confidence in what we are doing here, because of the great need the country has to develop these resources for our energy needs. What we also need to do at the same time is get together and make sure we are trying to provide the confidence the public needs to allow this to happen, and you won't see in the long haul these situations where there is an unknown or there is uncertainty or that States like New York, for instance, have to stop all activity because they are just trying to find out what is going on.

So we need to be looking at it from that perspective on a national level. How do we create that public confidence to move forward in the ways we need to move forward?

So I appreciate the chance to share some of these thoughts with the committee.

Senator CARDIN. We fully agree and want to work with you closely. The Chesapeake Bay Foundation and a host of other groups have petitioned the Obama administration to conduct a programmatic environmental impact statement to help understand the impact of all of the wells being currently operated.

Without objection, I will include in the record the copy of their petition.

[The referenced document was not received at time of print.]

Senator CARDIN. Thank you very much for your testimony.

Mr. PERCIASEPE. Thank you.

Senator CARDIN. We will now turn to our second panel, which consists of Dr. Bob Summers, the acting secretary of the Maryland Department of the Environment; Dr. Dan Volz, the director of the Center for Healthy Environments and Communities; Mr. Jack Ubinger, senior vice president, Pennsylvania Environmental Council; Jeff Cloud, the vice chairman of the Oklahoma Corporation Commission; and David Neslin, the director of the Colorado Oil and Gas Conservation Commission.

We will start with Dr. Summers. Welcome.

STATEMENT OF ROBERT SUMMERS, ACTING SECRETARY OF THE ENVIRONMENT, MARYLAND DEPARTMENT OF THE ENVIRONMENT

Mr. SUMMERS. Thank you.

Chairman Cardin, Ranking Member Inhofe, honorable Members of the committee, thank you for the opportunity to share Maryland's experience and concerns with hydraulic fracturing in the Marcellus Shale. I am Bob Summers, acting secretary, Maryland's Department of the Environment.

The Marcellus Shale formation underlies Garrett County and part of Allegany County in Maryland in the far western part of our

State. In these two counties, gas companies have leased the gas rights on more than 100,000 acres.

We are just beginning to enter into this. We currently have applications from two companies for a total of five wells. We are very mindful of the tremendous benefits that could accrue tot he environment and the economy by exploring and exploiting these gas reserves, but we are equally alert to the risks of adverse public health and environmental effects.

Our paramount concern is protecting public health, the environment, and our ground and surface water quality. We are proceeding cautiously and deliberately and do not intend to allow drilling and fracking in the Marcellus Shale in Maryland until these issues are resolved to our satisfaction.

There are numerous issues. We have heard a lot about those already. Some of the things we are particularly concerned about are the adequacy and sustainability of surface water and groundwater in the region to supply fracking; minimum requirements for constructing casing and cementing wells; minimum requirements for the integrity testing of those wells; requirements for installing and testing blowout prevention equipment; the potential for gas migration up from the well, including migration that can be induced from some of those layers that the well goes through versus failure of the well itself; toxicity in transport of fracking fluids; proper handling and disposal of naturally occurring radioactive materials, and many other aspects of this complex operation that need to be controlled.

In Maryland, we are moving forward. We anticipate to take it in two stages in doing this. First, over the next year, we are surveying existing practices and selecting best practices for drilling and fracking of wells. These will cover all aspects of safe preparation and design, delivery and management materials, drilling casings, cementing, fracking and waste disposal.

After we develop this interim we will call it gold standard, we will consider issuing permits for a small number of exploratory wells to be drilling and fracked in Maryland and we will carefully monitor these to provide more detailed information that we can use in order to take the second step in our process, using the data from the exploratory wells, along with the results of other research we are gathering from the surrounding States and other areas.

If we determine that gas production can be accomplished without unreasonable risks to human health and the environment, the Department could then make decisions on applications for production wells. Permit conditions will reflect all of these best practices and avoid public health and environmental harm.

We need the Federal Government to take a more active role in studying and regulating activities such as deep drilling, horizontal drilling, hydraulic fracking and waste disposal. While we believe States should retain the responsibility and should be able to enact more stringent requirements if they desire, the Federal regulatory floor will ensure at least basic protection of public health.

We believe that Federal technical support and oversight such as occurs now with the Clean Water Act and Safe Drinking Water Act are particularly important to protect our interstate waters such as the Susquehanna River, the Potomac River, Chesapeake Bay, which are all critical resources. In fact, today we have right here probably Potomac River water which also needs to be protected for the citizens in this area.

We commend Congress for directing U.S. EPA to conduct this research. The States need the Federal Government to lead and lend resources to help us in this effort. We support the legislation that we have just heard discussed today to allow regulation under the Federal law, under the Safe Drinking Water Act and to require disclosure.

So thank you for taking the initiative to inquire into this important issue and for providing this opportunity. I would be happy to answer any questions.

[The prepared statement of Mr. Summers follows:]

Testimony of Robert M. Summers, Ph.D.
Acting Secretary of the Maryland Department of the Environment
Environment and Public Works Committee
Subcommittee on Water and Wildlife
Tuesday, April 12, 2011

"Hydraulic Fracturing in the Marcellus Shale and Water Quality"

Chairman Boxer, Chairman Cardin, Ranking members Inhofe and Sessions and honorable members of the Committee, thank you for the opportunity to share Maryland's experience and concerns with hydraulic fracturing in the Marcellus Shale.

The Marcellus Shale in Maryland

The Marcellus Shale formation underlies Garrett County and part of Allegany County in the far western portion of Maryland. In these two counties, gas companies have leased the gas rights on more than 100,000 acres. The Maryland Department of the Environment issues permits for oil and gas wells, and we received our first permit application for drilling and hydraulic fracturing ("fracking") in the Marcellus Shale in 2009. No permits have yet been issued. We currently have applications pending from two companies for a total of 5 wells. We are mindful of the tremendous benefits that could accrue to the environment and the economy by exploring and exploiting our gas reserves, but we are equally alert to the risks of adverse public health and environmental effects. Our paramount concern is protecting our ground and surface waters.

Having observed events in Pennsylvania during the first few years of Marcellus Shale drilling there, Governor O'Malley, the Department of the Environment, and the Department of Natural Resources are determined to ensure that drilling will not start in Maryland until we know whether, and how, it can be done safely. We are proceeding cautiously and deliberately and do not intend to allow drilling and fracking in the Marcellus Shale until the issues are resolved to our satisfaction.

An industry representative estimated that as many as 1,600 wells could be drilled in 128,000 acres in Garrett County and 637 wells in 51,000 drillable acres in Allegany County. There is a huge potential economic impact. Lease payments, royalties, and in Garrett County, severance taxes, and the economic activity associated with drilling-related jobs could bring an economic boom to these western counties and some of their citizens. The consequences of a later economic collapse and the cost of the potential environmental damage are harder to quantify.

Although Maryland has not permitted any Marcellus wells, the Department of the Environment has been attentive to the possible shipment of fracking fluid into Maryland since late 2008. Some flow back from fracking in another state was shipped to Baltimore for treatment and disposal in 2009. The fracking fluid was pretreated and sent to a large municipal wastewater treatment plant that discharges to brackish water and not upstream of any drinking water intake. For these reasons, and because of the small volume of fracking fluid relative to the flow from the wastewater treatment plant, this handling posed little or no risk. A different situation could exist, however, if concentrated fracking water were not treated adequately and discharged upstream of a drinking water intake. Concurrently, we have had discussions with EPA Region III, which is advising states on monitoring to ensure that drinking water remains safe.

Environmental, Public Health and Public Safety Concerns

There are numerous issues that need to be addressed before Maryland can conclude whether and how drilling in the Marcellus Shale can be done safely. They include:

- minimum requirements for constructing, casing and cementing wells
- minimum requirements for integrity testing of wells
- minimum requirements for installing and testing blowout prevention equipment
- the potential migration of gas from the well, including migration from induced or naturally occurring faults and fractures
- the toxicity, fate and transport of fracking fluid
- proper handling and disposal of naturally occurring radioactive materials
- best practices for managing and disposing of flow back
- best practices for managing and disposing of drilling mud and drill cuttings
- best practices for containment and management of fuels and other liquids
- air pollution, including ozone production
- re-fracturing and its potential effect on well integrity
- avoiding habitat fragmentation, invasive species, and damage to wetlands and streams from access roads, drill pads, gathering lines, and ancillary operations
- avoiding other impacts to aquatic ecosystems, including stream sedimentation from damaged roads and dust from truck traffic
- the adequacy and sustainability of surface water and ground water in the region to supply water for fracking
- public safety and emergency response services

Maryland Legislation

Public concern brought the issue of Marcellus Shale drilling to the attention of Maryland legislature, which started its 90-day session on January 12, 2011. Bills were introduced to speed the issuance of drilling permits, place the burden on each applicant for a permit to demonstrate the safety of drilling and fracking, and require a study before permits could be issued. The Governor and the Department supported a bill to require the State to perform a comprehensive study of short-term, long-term and cumulative effects of hydraulic fracturing, to be paid for by those gas companies holding leases in Maryland. Until publication of the report, the legislation would prohibit the Department from issuing a permit involving hydraulic fracturing unless it can be done without adverse impact to human health, natural resources, or the environment. As this is being written, the fate of these various bills in the Maryland legislature in unknown.

How the Maryland Department of the Environment Proposes to Proceed

We anticipate moving forward in two stages. First, during the next year, we will survey existing practices and select Best Practices for the drilling and fracking of wells. These Best Practices will cover all aspects of site preparation and design, delivery and management of materials, drilling, casing, cementing and fracking. After we develop this interim "gold standard" the Department will consider issuing permits for a small number of exploratory wells to be drilled and fracked in the Marcellus Shale using these standards. Sites eligible for these exploratory permits must present minimum risks to human health and the environment. The permit will be conditioned on the company's commitment to collect and share with the State data from drilling, fracking and monitoring to advance our understanding of the risks and the adequacy of the Best Practices.

Second, we will use the data from these exploratory wells, along with the results of other research as it becomes available, to evaluate the environmental viability of gas production from the Marcellus Shale. This phase will focus on long-term and cumulative risks, and include landscape level effects like forest fragmentation. If we determine that gas production can be accomplished without unreasonable risk to human health and the environment the Department could then make decisions on applications for production wells. Permit conditions would be drafted to reflect Best Practices and avoid environmental harm. At this time, the State has not identified a source of funding for this work, other than the proposed legislation mentioned above.

The Need for Federal Leadership

We need the federal government to take a more active role in studying and regulating activities such as deep drilling, horizontal drilling, hydraulic fracturing, and waste disposal. While the states should retain the authority to enact more stringent requirements, a federal regulatory "floor" would ensure at least basic protection of the environment and public health. In previous administrations, the balance has been struck in favor of energy production over environmental protection. For example, gas and oil exploration and production wastes are excluded from RCRA Subtitle C regulation. The injection of hydraulic fracturing fluids is excluded from the Safe Drinking Water Act's Underground Injection Program. The Clean Water Act was amended to expand the exemption of stormwater runoff to cover all oil and gas field activities and operations, not just uncontaminated stormwater runoff from certain operations. In the absence of a strong federal regulatory program, the burden of assuring that wells can be safely drilled and hydraulically fractured in the Marcellus Shale falls on the states individually. Maryland believes that federal technical support and oversight of state regulatory programs such as those administered under the Clean Water Act and the Safe Drinking Water Act are particularly important to ensure appropriate protection of interstate waters such as the Susquehanna and Potomac Rivers and the Chesapeake Bay, which are critical resources to all of the jurisdictions in the region.

We commend Congress for directing the United States Environmental Protection Agency (EPA) to conduct research to examine the relationship between hydraulic fracturing and drinking water resources. EPA's Office of Research and Development has developed a solid, comprehensive plan for this study; however, we note that some important issues are beyond the scope of the study, including re-fracturing, and impacts to air quality and terrestrial and aquatic ecosystems.

We are also encouraged by President Obama's "Blueprint for a Secure Energy Future," which he announced on March 30. In particular, we welcome the plan to have the Energy Advisory Board establish a subcommittee to identify immediate steps that can be taken to improve the safety and environmental performance of fracking and to develop consensus recommendations for federal agencies on practices that will ensure the protection of public health and the environment. The offer of technical assistance from DOE and EPA is also welcome.

The states need the federal government to lead and to lend its resources to the effort and we need a strong state-federal partnership. Timing and other factors probably preclude using an exploratory well in Maryland for one of the prospective case studies planned for the EPA report, but we intend to seek EPA guidance on the study plan for the prospective case study so that Maryland can gather the most relevant data if a permit is issued for an exploratory well. We also intend to seek technical assistance from the USGS in determining what to monitor in the process of drilling and fracking wells for exploration, and in analyzing the data we obtain. Preliminary guidance from EPA on the proper spatial area for monitoring and recommendations for Best Practices to prevent environmental impacts from drilling and fracking operations would be very helpful until the EPA study can be completed. Lastly, EPA should develop water quality criteria for conductivity (specific to chemical species), dissolved solids and salinity in freshwater, as well as pretreatment standards and effluent limitations for fracking flowback.

Under existing federal law, hydraulic fracturing is excluded from Safe Drinking Water Act regulation of underground injection. The chemicals added to fracking fluid do not have to be disclosed. We support the Fracturing Responsibility and Awareness of Chemicals Act, S.587, which was introduced on March 15, 2011, by Senator Casey and co-sponsored by Senator Cardin. The Bill would reinstate regulation of hydraulic fracturing under the Safe Drinking Water Act and require the person conducting hydraulic fracturing operations to disclose to the government all of the chemical constituents used in hydraulic fracturing. Proprietary chemical formulas could still be protected from public disclosure. These are positive steps, although we encourage a reexamination of scope of protection for proprietary information. The public has an important interest in knowing what chemicals are being injected underground.

The Chesapeake Bay Foundation and other groups have filed a petition with the federal government for a Programmatic Environmental Impact Statement to address the risks and cumulative impacts of the extraction of natural gas from the Marcellus Shale formation in the Chesapeake Bay watershed. We support the goal of a comprehensive assessment, and we note that portions of the Marcellus Shale lie to the west of the Eastern Continental Divide, and that the environment outside the Chesapeake Bay watershed deserves protection, too.

Thank you for taking the initiative to inquire into this important issue and for providing the opportunity to share Maryland's perspective.

Senator CARDIN. Thank you, Dr. Summers.

Now, I will turn to Dr. Volz.

STATEMENT OF CONRAD DANIEL VOLZ, DIRECTOR, CENTER FOR HEALTHY ENVIRONMENTS AND COMMUNITIES

Mr. VOLZ. Thank you all for the opportunity to testify this morning at this joint hearing on public health and environmental impacts. I believe that unconventional gas extraction in deep shale deposits presents considerable risks to public health and safety, as well as to environmental resources, particularly water quality and aquatic organisms.

My testimony today is going to cover three critical public health and environmental policy areas related to unconventional natural gas production. No. 1, it is largely unregulated siting of these wells, patterns of violations from Marcellus Shale wells that show impacts on water resources, and finally I think a very important issue that has been brought up a couple times, the toxic substances that are entering surface water sources from disposal of flow-back waters through brine treatment and sewage treatment plants.

First of all, I am going to talk about the unregulated siting of natural gas wells in areas of high population density, which also occurs near schools, critical infrastructure. This is shown in slide three of my presentation that I gave to the committees today. Unconventional gas extraction wells are highly industrialized operations that bear little resemblance to what we know in Northeastern United States of conventional oil and gas exploration.

These wells are highly, as I said, highly industrialized and there can be risks of catastrophic blowout, explosion, and/or fire. Any of these can create an immediately dangerous to life and health situation.

The unregulated siting of unconventional natural gas wells and production facilities in residential neighborhoods and near critical infrastructure is very unwise public health preparedness policy, especially in light of the tens of billions of dollars that we are spending at Federal and State level to reduce risk from terror attacks on USA citizens and damage to critical infrastructure.

Second, the higher rates and differential patterns of Oil and Gas Act violations, and they are listed on slide four of my presentation, are very different as compared to conventional oil and gas wells, and suggest a much greater impact to drinking water and aquatic resources.

We have done a study at my outfit that shows that Marcellus wells have about a 1.5 to four times, depending on the denominator you use, more violations than conventional oil and gas wells per offending well, and that those violations are more serious and that the violations have a more direct impact on water quality, things like failures to minimize accelerated erosion, implement erosion and sedimentation plans, discharge of pollution to the waters of the Commonwealth of Pennsylvania, many general violations of the Clean Streams law, failure to properly store, transport, process or dispose of residual wastes, and failures to adequately construct or maintain these impoundments that hold actually toxic flow-back water.

The third problem and a problem that my group has been looking at, both sewage treatment plants and brine treatment plants, we have been looking at the disposal of flow-back fluids through these plants. We sampled a brine treatment facility in Indiana County, PA called Pennsylvania Brine Treatment, Josephine Facility, and we found that coming out of the effluent pipe of that plant was discharge of nine pollutants, essentially all in excess of nationally recognized human and/or aquatic health standards into the nearby Blacklick Creek.

These contaminants included barium, and what was coming out in the effluent was eight times the minimum risk level in drinking water for children and 27 times the EPA consumption concentration for fish and fish-plus-water. Strontium was found. Bromide was coming out in the effluent water and its level was almost 10,000 times the level that the water treatment facilities like to see in background water of 100 parts per billion. Benzene was found coming out at two times the drinking water standard and six times its EPA consumption criteria and 1.5 times the drinking water minimum risk level for children.

Last, we found butoxyethanol coming out of the effluent pipe. This is a glycol ether that is used in Marcellus Shale gas extraction. We found it coming out at between 24 to 55 times the derived drinking water minimum risk level for intermediate exposure for men, women and children.

Thank you very much.

[The prepared statement of Mr. Volz follows:]

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Director & Principal Investigator, Center for Healthy Environments and Communities (CHEC); Director, Environmental Health Risk Assessment Certificate Program; Assistant Professor of Law (Secondary Appointment)

Before the Senate Committee on Environment and Public Works and its Subcommittee on Water and Wildlife, Joint Hearing "Natural Gas Drilling, Public Health and Environmental Impacts", April 12, 2011

Thank you for the opportunity to testify this morning at the Joint Hearing on Natural Gas Drilling, Public Health and Environmental Impacts. Unconventional gas extraction in deep shale deposits presents considerable risks to public health and safety as well as to environmental resources, particularly water quality and aquatic organisms. My testimony today will cover three critical public health and environmental policy areas related to unconventional natural gas production.

First is the unregulated siting of natural gas wells in areas of high population density, and near schools and critical infrastructure. Unconventional gas extraction wells are highly industrialized operations that have public health preparedness risks of catastrophic blowout, explosion and fire. Any of these incidents can create an Immediately Dangerous to Life and Health (IDLH) condition for adults or children in close physical proximity. The unregulated siting of unconventional natural gas extraction wells and production facilities in residential neighborhoods and near critical infrastructure is unwise preparedness policy, especially in light of federal and state efforts to reduce risk from terror attacks on USA citizens and critical infrastructure.

Secondly, the higher rates and differential patterns of oil and gas act violations from Marcellus Shale gas extraction operations, as compared to conventional oil and gas wells, suggests a much greater impact to drinking water and aquatic resources. Marcellus Shale gas extraction wells have between 1.5 to 4 times more violations than their conventional well counterparts per offending well, including more serious violations and violations that have a direct impact on water quality and aquatic resources. Marcellus Shale gas extraction wells are more likely to have violations for:

- Failures to minimize accelerated erosion, implement erosion and sedimentation plans, and/or maintain erosion and sedimentation controls.
- Discharge of pollution to waters of the Commonwealth of Pennsylvania.
- General violations of the Clean Streams Law.

- Failure to properly store, transport, process or dispose of a residual waste and -
- Failures to adequately construct or maintain impoundments holding gas extraction flowback fluids containing toxic contaminants.

The third problem public health and environmental policy area to be addressed is the disposal of gas extraction flowback fluids, carrying a plethora of toxic elements and chemicals, in inefficient "brine" treatment facilities and Publicly Owned Treatment Works (POTW's) [commonly called sewage treatment plants], which discharge effluent into surface water sources. Studies of the effluent from a commercial facility in Pennsylvania that treats fluids only from gas and oil operations shows discharge of 9 pollutants in excess of nationally recognized human and/or aquatic health standards into a nearby stream. The contaminants include:

- Barium, found in effluent over 8 times its minimum risk level (MRL) in drinking water to children and 27 times its EPA consumption concentrations for fish and "fish plus water".
- Stable Strontium, found in effluent 43.29, 51.68 and 97.90 times the drinking water MRL's for intermediate exposures for adult men, adult women, and children, respectively. Strontium levels found in effluent were 29,811 times the reporting limit in the plants NPDES permit.
- Bromide, which forms mixed chloro-bromo byproducts in water treatment facilities that have been linked to cancer and other health problems were found in effluent at 10,688 times the levels generally found acceptable as a background in surface water.
- Benzene, a known carcinogen, is present in effluent water at over 2 times its drinking water standard, over 6 times its EPA consumption criteria, and 1.5 times the drinking water MRL for chronic exposure for children.
- 2-butoxyethanol (2-BE), a glycol ether and used as an antifoaming and anti-corrosion agent in slick-water formulations for Marcellus Shale gas extraction was found in effluent water at 24.48, 29.21, and 55.14 times the drinking water MRL's for intermediate exposure to adult males, adult females, and children, respectively –based on hepatic health effects.
- Chlorides, the concentration of chlorides in the effluent was 138 and 511 times the EPA maximum and continuous concentration criteria set for the health of aquatic organisms, respectively.

Due to time constraints I will not cover impacts to air quality, although I wish to go on record that these impacts could be significant, due to release of hazardous air pollutants from 10's of thousands of projected natural gas wells, with the subsequent formation of ozone; areas of Maryland, Pennsylvania, Ohio, New York, and New Jersey are already in EPA nonattainment status for ozone exposure.

Potential "Immediately Dangerous to Life and Health" (IDLH) Conditions from Unregulated Siting of Unconventional Gas Extraction Wells

Unconventional gas extraction wells are highly industrialized operations that have attendant risks of catastrophic blowout, explosion and fire. The actualization of any of these incidents creates an IDLH condition for adults and children in close proximity to these wells from any blast or fires, the displacement of oxygen by methane, exposure to waterborne contaminants, and from inhalation of pyrolysis products of burning condensate, liners and/or production equipment. Over the past 2 years, within a 3 hour drive of Pittsburgh PA, there has been one catastrophic blowout, one explosion and fire due to ignition of methane from an underground coal mine, and two fires (one at a multi-well site in production near Avella PA and one at a site being brought into production in Hopewell Township, PA).

If we use the figure of 1831 drilled wells in the State of Pennsylvania from 2007 to September of 2010, which is an overestimate of the wells drilled in a three hour drive of Pittsburgh PA and use this as the denominator, and use 4 incidents as the numerator we obtain an order of magnitude estimate of the probability for IDLH conditions at these wells of 0.002. Using this figure and based on estimates of the predicted number of wells to be drilled over the next 10 years of 25,000 wells- there could be as many as 50 wells that create IDLH conditions due to blowout, blast and/or fire. What is disturbing, in this era of spending billions of dollars to reduce risk from terror attacks on USA citizens and critical infrastructure, is that we are allowing these gas extraction wells to be sited in a largely unregulated fashion in close proximity to homes and critical infrastructure including schools, and in densely populated regions of Pennsylvania, Ohio, and West Virginia.

The well publicized and documented Marcellus Shale blowout in Clearfield County PA, due in part to failure of the operator to properly test the Blow-Out Preventers (BOPs) prior to use and to conduct the BOP test in a proper manner, resulted in the immediate evacuation of all residents within one mile of the drill site. Luckily the impacted area was largely state forest land with no population proximal to the drill site and very diffuse population density. CHEC has done projections to show impacts of such a blowout in a more densely populated area south of Pittsburgh PA- Peters Township, Washington County PA, where gas leases are currently being signed. If the blowout had occurred in the centroid of this township approximately 1,928 adults and children would need to be evacuated as well as up to 5 school complexes. Local emergency response personnel are not properly trained or adequately equipped to handle these type incidents nor is there a gas extraction specific planning mechanism for such large population displacements.

Patterns of Oil and Gas Violations from Marcellus Shale Gas Extraction Operations in Pennsylvania and General Threats to Water Resources

CHEC analyzed the number of Oil and Gas Act violations by well type in Pennsylvania over the period from January 1, 2007 to September 30, 2010 and found that Marcellus Shale gas extraction wells have between 1.5 to 4 times more violations than their conventional well counterparts per offending well (this is dependant on the denominator of total wells drilled which is difficult to ascertain for conventional oil and gas wells due to drilling for over 100 years). These include more serious violations and violations that potentially have a more direct impact on water quality and aquatic resources. Between January 1, 2007 and September 30, 2010, horizontal Marcellus wells had 3.75 violations per offending well, while vertical Marcellus wells had 2.99 violations per offending well, resulting in a rate of 3.51 violations per offending well for all Marcellus wells. Conventional non-Marcellus oil and gas wells had violations per offending well of 2.38.

In 2010, 451 distinct Marcellus Shale gas extraction wells in Pennsylvania were cited for violations of the Oil and Gas Act by the Pennsylvania Department of Environmental Protection (DEP). There were 1544 total violations resulting in a mean violations rate per offending well of 3.42. Of these 1544 total Marcellus violations; 111 violations were for failure to minimize accelerated erosion, implement erosion and sedimentation plans, and/or maintain erosion and sedimentation controls and/or failure to stabilize the site until total site restoration under OGA Section 206(c)(d); 105 violations were for discharge of pollution to waters of the Commonwealth; 106 violations were general violations of the Clean Streams Law; 68 violations were for failure to properly store, transport, process or dispose of a residual waste; and 116 violations were issued for impoundment problems including failure to maintain a 2 foot freeboard, and impoundment not structurally sound or impermeable.

These patterns of violations of the Pennsylvania Oil and Gas Act by Marcellus Shale gas operators support my contention that development of natural gas from the Marcellus Shale has the potential to result in substantial adverse effects on water quality, the environment and public health. Ground-surface disturbances associated with well drilling, including site clearing, and the construction of access roads, drill pads and impoundments, can produce impacts associated with stormwater, erosion and sedimentation of surface waterways, which in turn may lead to higher levels of water turbidity, total dissolved solids, conductivity and salinity. In addition to the impacts associated with surface activities are those associated with deep well drilling. Wells drilled to depths of 5,000 to 8,000 feet to reach the Marcellus formation (and also the Utica Shale formation) create pathways for the migration of naturally-occurring contaminants into usable quality aquifers, and involve the disposition on the surface of drill cuttings and formation waters that also may contaminate ground and surface water. Contaminants associated with natural gas drilling in the Marcellus include toxic heavy metals and elements, organic compounds, radionuclides and acid producing sulfide minerals, and natural gases and sulfide producing gases, which can threaten surface and groundwater sources.

Disposal of Oil and Gas Flowback Fluids in Inefficient "Brine" Treatment Facilities and Publicly Owned Treatment Works (POTW's) that Discharge into Surface Water; Potentially Exposed Populations and Regional Significance

Hydraulic fracturing (HF) of shale gas deposits uses considerable masses of chemicals, for a variety of purposes to open and keep open pathways through which natural gas, oil and other production gases and liquids can flow to the wellhead. HF, also known as slick-water fracturing, introduces large volumes of amended water at high pressure into the gas bearing shale where it is in close contact with formation materials that are enriched in organic compounds, heavy metals and other elements, salts and radionuclides. Typically, about 1 million gallons and from 3 - 5 million gallons of amended water are needed to fracture a vertical well and horizontal well, respectively (Hayes, 2009). Fluids recovered from these wells can represent from 25% to 100% of the injected solution and are called "flowback" or "produced" water depending on the time period of their return. Flowback and produced water contain high levels of total dissolved solids, chloride, heavy metals and elements as well as enriched levels of organic chemicals, bromide and radionuclides – in addition to the frac chemicals used to make the water slick-water. Levels of shale origin contaminants in flowback water generally increase with increasing time in contact with formation materials.

This oil and gas fluid waste is generally held in temporary open-air impoundment(s) near the well site or occasionally in large sealed containers. Additionally, oil and gas waste fluids accumulate in condenser tanks located on producing well pads, which must be drained regularly. Currently, flowback water is either taken for disposal to a POTW (sewage treatment plant), or a Brine Treatment Facility, both of which discharge effluent directly to surface water sources. The waste fluids may also be recycled for reuse (on-site or off-site at treatment facilities), or injected into Class II underground wells.

The relative volumes of flowback and condensate entering each end-point alternative described above are currently the subject of much heated debate, the unraveling of which is well beyond the scope of my testimony. It is sufficient to note that large volumes of oil and gas wastewater are disposed of in POTW's and brine treatment facilities that discharge effluent directly into surface water. The PA Brine Treatment, Josephine Facility received 15,728,242 gallons of Marcellus Shale gas extraction wastewater for treatment and effluent discharge into Blacklick Creek, Indiana County in the last half of 2010. The Clairton POTW received and disposed of 53,473 gallons of Marcellus Shale wastewater in the last half of 2010, which is ultimately discharged into the Monongahela River. CHEC has identified at least 10 facilities that discharged effluent into the Monongahela River drainage in 2010-2011 in Pennsylvania alone; if all these facilities are accepting flowback fluids at their permitted rate then 824,000 pounds of total dissolved solids and 15,000 pounds of barium could enter the watershed from these operations daily.

There is considerable scientific inquiry and even controversy regarding the potential of vertical or horizontal fracturing of shale gas reservoirs to contaminate shallow or confined groundwater aquifers, and thus expose municipal or private well water users to chemicals used in the hydrofracturing process and/or contaminants in the formation materials. However, when Marcellus Shale flowback and produced fluids are disposed of in POTW's or inefficient brine treatment facilities discharging into surface water, the fate and transport pathways to expose human and aquatic receptors are well described for most of the contaminants potentially in effluent discharge water and known to be in flowback and other oil and gas wastewater. Contaminants untreated by the facility and discharged into surface water will move in the water through advective and fickian processes downstream, be deposited and transferred into sediments and pore water, bioaccumulate in aquatic receptors and terrestrial animals that feed on them according to their species specific bioaccumulation factors, be transported to groundwater, and/or be volatilized to air dependent on their Henry's Law constants. Direct and complete human and ecological exposure pathways via ingestion, dermal absorption and inhalation (gill transfer in fish) can be demonstrated for different classes of elements, and compounds in the wastewater, constituting a potential exposure threat to recreationalists, private well water users and municipal drinking water users.

Case Example; Concentrations of Contaminants in Effluent Water from Pennsylvania Brine Treatment Facility, Josephine Facility (PBT-JF)

The Center for Healthy Environments and Communities (CHEC) of the Graduate School of Public Health, University of Pittsburgh, conducted sampling of wastewater as it was discharged into Blacklick Creek, Indiana County, Pennsylvania from the PBT-JF on December 10, 2010. Samples were taken at 3-hour intervals over the course of one 24-hour period. The concentrations of analyzed contaminants in this effluent of primary environmental public health importance, which may also stress aquatic life, include: barium (Ba) [mean, 27.3 ppm; maximum, 37.0 ppm]; bromides (Br) [mean, 1068.8 ppm; maximum, 1100.0 ppm; strontium (Sr) [mean, 2983.1 ppm, maximum 3120.0 ppm]; benzene [mean 0.012 ppm; maximum 0.013 ppm] and 2-butoxyethanol (2-BE) [mean 59ppm; maximum 66 ppm]. Contaminant concentrations of ecological and secondary drinking water importance include: chlorides (Cl) [mean 117,625 ppm, maximum 125,000 ppm]; magnesium (Mg) [mean 1247.5 ppm; maximum 1300.0 ppm]; total dissolved solids (TDS) [mean 186,625 ppm; maximum 190,000 ppm]; sulfate (SO4) [mean 560 ppm; maximum 585 ppm], and pH [mean 9.58 units; maximum 10 units].

Levels of contaminants in effluent from the PBT-JF were interpreted according to comparisons with applicable federal and state standards and recommended guidelines for both human and aquatic health. Barium had a mean concentration in effluent of 27.3 ppm (maximum of 37 ppm); this is approximately 14 times the United States Environmental Protection Agency (EPA) maximum concentration limit (MCL) of Ba in drinking water of 2 ppm. The EPA consumption concentrations 'water and organism' and 'organism alone' for barium are both 1 ppm. The levels of barium in the effluent are over 27 times these consumption concentrations. The U.S. EPA criteria maximum concentration (CMC) and the EPA criteria continuous concentration (CCC), both for protection of aquatic health, are 21 ppm and 4.1 ppm, respectively; the mean level of barium in effluent exceeds these criteria by 1.3 and 6.7 times, respectively. The mean concentration of barium in PBT-JF effluent water (27.3 ppm) is 3.96, 4.73, and 8.98 times the ATSDR derived drinking water minimum risk level (MRL) for intermediate and chronic exposures for adult men, and women, and children, respectively.

The EPA (ATSDR ascribed) recommends that drinking water levels of stable strontium should not be more than 4 milligrams per liter of water (4 mg/L), Sr levels in PBT-JF effluent are 746 times this recommended level. The strontium ATSDR MRL for oral route, intermediate exposure is 2 mg/kg of body mass/day, for musculoskeletal endpoints. The derived minimum risk levels for strontium in drinking water for intermediate exposure for adult men, adult women, and children are 68.87 mg/L/day, 57.67 mg/L/day, and 30.45 mg/L/day, respectively. The mean concentration of strontium in PBT-Josephine effluent water (2,981.1 ppm) is 43.29, 51.68 and 97.90 times the derived strontium drinking water MRL's for intermediate exposures for adult men, adult women, and children, respectively. Strontium is not listed on the PBT-JF, NPDES permit but the facility is required to notify the PA DEP if they routinely discharge 100 ppb of a toxic pollutant or nonroutinely discharge 500 ppb of a toxic pollutant. The mean concentration of Sr in effluent water of 2,981.1 ppm is 29,811 and 5,962 times the lower and upper notification levels required by the PA DEP NPDES permit, respectively. . Searches of the PA DEP file for December, 2010, shows no such notification to the DEP.

Bromide in water is of concern because of its ability to form brominated analogs of drinking water disinfection by-products (DBP). Specifically, bromide can be involved in reactions between chlorine and naturally occurring organic matter in drinking-water, forming brominated and mixed chloro-bromo byproducts, such as trihalomethanes or halogenated acetic acids. Several DBPs have been linked to cancer in laboratory animals, and as a result the U.S. EPA has regulated some DBP's. There is general agreement that bromide levels in freshwater sources be kept below about 100 ppb (.1 ppm) so that formation of brominated DBP's are minimized, therefore regulatory authorities and water treatment plant operators become concerned when there are sources of bromides in a surface system adding to this level. The PBT-JF discharged effluent into Blacklick Creek with a measured mean concentration of bromide of 1,068.8 ppm, which is 1,068,800 ppb. This is 10,688 times the 100 ppb level at which authorities become concerned. Bromide is not listed on the PBT-JF NPDES permit, but the facility is required to notify the PA DEP if they routinely discharge 100 ppb of a toxic pollutant or nonroutinely discharge 500 ppb of a toxic pollutant. The mean concentration of Br in effluent water 1,068.8 ppm is 10,688 and 2,138 times the lower and upper notification levels required by the PA DEP NPDES permit, respectively. Searches of the PA DEP file for December, 2010, shows no such notification to the DEP.

The mean level of benzene, a known carcinogen, in outfall effluent from PBT-JF was 0.012 ppm or 12 ppb. The drinking water MCL for benzene is 5 ppb, thus effluent levels were above twice the drinking water MCL. The EPA consumption, water and organism risk level for benzene is 2.2 ppb in water, the mean level of benzene in PBT-Josephine effluent water is almost 6X this criteria; the organism only risk level for benzene is 50 ppb in water, the mean level of benzene in effluent water is 24% of this guideline. The benzene ATSDR MRL for oral route, chronic exposure is 0.0005 mg/kg of body mass/day, for immunological endpoints. The derived minimum risk levels for benzene in drinking water for chronic exposure for adult men, adult women, and children are 0.017 mg/L/day, 0.014 mg/L/day, and 0.008 mg/L/day, respectively. The mean concentration of benzene in PBT-Josephine effluent water (0.012 ppm) is 70% of, 86% of, and 1.5 times the derived chronic drinking water MRL for benzene for adult men, adult women, and children, respectively.

2-butoxyethanol (2-BE) is a glycol ether and is used as an antifoaming and anti-corrosion agent, as well as an emulsifier in slick-water formulations for Marcellus Shale gas extraction. The mean and maximum levels of 2-BE found in the PBT – JF effluent were

59 ppm and 66 ppm, respectively. The 2-BE ATSDR MRL for oral route, acute exposures is 0.4mg/kg/day based on hematological effects, with an uncertainty factor of 90; the 2B-E MRL for oral route, intermediate exposure is 0.07 mg/kg/day and it is based on hepatic health endpoints with an uncertainty factor of 1000. The derived minimum risk levels for 2-BE in drinking water for acute exposure for adult men, adult women, and children are 13.77 mg/L/day, 11.53 mg/L/day, and 6.09 mg/L/day, respectively; the derived MRL's for 2-BE in drinking water for intermediate exposure for adult men, adult women, and children are 2.41 mg/L/day, 2.02 mg/L/day, and 1.07 mg/L/day, respectively. The mean concentration of 2-BE in PBT-JF effluent water (59 ppm) is; 4.28, 5.12, and 9.69 times the derived 2-BE drinking water MRL's for acute exposure to adult males, adult females, and children, respectively; and 24.48, 29.21, and 55.14 times the derived 2-BE drinking water MRL's for intermediate exposure to adult males, adult females, and children, respectively. 2-BE is not listed on the PBT-JF NPDES permit, but the facility is required to notify the PA DEP if they routinely discharge 100 ppb of a toxic pollutant or nonroutinely discharge 500 ppb of a toxic pollutant. The mean concentration of 2-BE in effluent water is 590 and 118 times the lower and upper notification levels, required by the PA DEP NPDES permit, respectively. Searches of the PA DEP file for December, 2010 show no such notification to the DEP.

Contaminants with secondary MCL's (SMCL) and aquatic receptor effects that were measured in the PBT-JF effluent include magnesium, manganese, chlorides, sulfates, and total dissolved solids (TDS). Magnesium was found in the effluent with a mean concentration of 1,247.5 mg/L, which is 24,950 times the EPA Mg SMCL of .05 mg/L. The mean concentration of Manganese in the effluent was .08 mg/L, and the SMCL for Manganese concentration in drinking water is .05 mg/L, which is 62.5% lower than the concentration in the effluent. The mean concentration of chlorides in the sample analysis was 117,625 mg/L, which is 470.5 times the SMCL for chlorides in drinking water of 250 mg/L. To protect aquatic communities, the criteria maximum concentration (CMC) for chlorides in surface water is 860 mg/L, and the criteria continuous concentration (CCC) for chlorides in surface water is 230 mg/L. The mean concentration of chlorides measured in samples was 138 times the CMC and 511 times the CCC. The mean concentration of sulfates in the sample analysis was 560 mg/L, 2.2 times the SMCL for sulfates in drinking water (250 mg/L). The SMCL for total dissolved solids (TDS) in drinking water is 500 mg/L, and the mean concentration of TDS measured in samples was 186,625 mg/L, 373 times the SMCL.

Masses of Contaminants Entering Blacklick Creek

CHEC has information from the Pennsylvania, Department of Environmental Protection (DEP) that the PBT – JF treated 15,728,241 gallons of oil and gas wastewater in the 6 month period from July 1, 2010 to December 31, 2010. Using this figure as the amount of effluent wastewater exiting the Josephine outfall and using the mean level of each contaminant found in the effluent over the sampling period of the study, the masses of contaminants with important human and ecological consequences discharged from the PBT-JF into Blacklick Creek in the last 6 months of 2010 are projected to be: barium-1627 kg (3588 pounds); strontium -177,712 kg (391,856 pounds; 196 tons); bromides-

63,708 kg (140,476 pounds; 70.2 tons); chloride – 7,011,631 kg (15,460,646 pounds; 7,730 tons); sulfate – 33,382 kg (73,607 pounds; 36.8 tons); 2 BE– 3517 kg (7,755 pounds; 3.88 tons); and total dissolved solids – 11,124,733 kg (24,530,036 pounds; 12,265 tons).

Potentially Exposed Populations

Recreationalists are at risk of being exposed to outfall contaminants through ingestion, inhalation and through dermal exposure. The outfall of the BBT-JF is easily accessible to users of nearby rails-to-trails pathways, and there are indications that anglers frequent the area. Additionally, children wade and swim in the creek during warmer weather, and regional watershed websites indicate that paddlers use the creek for canoeing and kayaking. 2 BE released into Blacklick Creek may be ingested by swimmers in the creek. This pollutant can become airborne and present an inhalation hazard to anglers, swimmers and boaters. It is also taken in to the body via dermal absorption. Anglers catching and eating fish from upstream or downstream of the effluent outfall are at risk for exposure to multiple contaminants that were sampled in this study. CHEC has developed maps showing numerous private water wells in the immediate vicinity of Blacklick Creek downstream from the effluent discharge. Private well water users are at risk of exposure to contaminants in effluent being released into Blacklick Creek because these private wells may capture water from the creek when the well pump rate is sufficiently high. High pump rates can occur especially during peak usage by residents. The first identified municipal drinking water intake downstream of this discharge is at Freeport, Pennsylvania on the Allegheny River. Populations served by the Freeport authority and water authorities downstream of Freeport are at potential risk for exposure to contaminants identified in effluent, as well as other contaminants in Marcellus Shale flowback water that were not sampled for in this study.

Implications of Effluent Discharge from the PBT – Josephine Facility Discharge For Exposures to Other Contaminants Known to be Present in Marcellus Shale Flowback Fluids and a Regional Appreciation of These Results

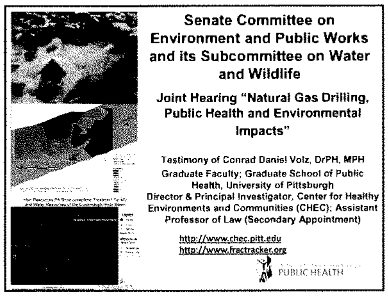
Of particular environmental public health significance is that Marcellus Shale flowback water contains other contaminants, in addition to those analyzed for in this study, which have health consequences if ingested, inhaled, and/or absorbed through the skin. While we make no statements regarding the presence of other contaminants in this effluent water being discharged into Blacklick Creek, it is imperative that additional testing be conducted immediately by federal and state health and enforcement agencies to determine if other contaminants of public health significance are entering this watershed. Additionally, oil and gas wastewater and Marcellus shale flowback fluids are being disposed of in "brine treatment" facilities and at POTW's throughout the Commonwealth of Pennsylvania and in Ohio, Maryland, West Virginia, and New York. The ramifications of disposal of large quantities of oil and gas wastewater through ineffectual brine treatment plants and POTW's needs further evaluation throughout the region to determine its impact on stream and river systems and public drinking water supplies, as well as to recreationalists and private well water users.

Local and Regional Public Health and Environmental Recommendations Based on PBT-JF Results

- The Pennsylvania Brine Treatment – Josephine Facility is discharging up to 60 ppm of 2-BE into Blacklick Creek, which is not listed in its discharge permit. Operations at this plant should be halted until all contaminants in accepted oil and gas fluids are known and it can be determined if the treatment processes used at the plant effectively remove these contaminants from the fluids being treated, so that effluent discharge concentrations of contaminants are consistent with human and aquatic health standards, guidelines and criteria. This recommendation should extended to other treatment plants and POTW's accepting Marcellus Shale flowback fluids in this drainage.
- All approaches to the effluent discharge area and a reasonable distance downstream (at least 100 meters) from stream-side and land-side should be posted with warning signs. These signs should discourage any use of and/or contact with stream water.
- An advisory should be issued to all anglers that fish taken from this stream, both up and down stream, may be contaminated and discouraging fish take and of course consumption.
- Studies to determine the levels of all potential Marcellus Shale flowback fluid contaminants in downstream water, sediments and pore water should be undertaken immediately. These should include sampling upstream of the effluent discharge point and at short, intermediate and longer distances downstream from the effluent discharge point. The number of samples taken (n) of surface water, sediments and pore water upstream and at the various distances downstream should be sufficient so that statistically significant differences of contaminant concentrations can be inferred. CHEC took additional samples of effluent and performed both up and downstream transect sampling on April 1st and 2nd, 2011- these samples are now being analyzed for an expanded list of chemicals including antimony, radium radionuclides, phenols and derivatives, polynuclear aromatic hydrocarbons (PAH's), phthalates, and total petroleum hydrocarbons
- Residential and other private well water users downstream of the effluent outfall of the PBT-Josephine Facility should be advised that there may be contaminants in their well water and discouraged from using it for drinking, cooking or bathing. Well water from wells in close proximity to Blacklick Creek should be tested to assure that contaminants in Marcellus Shale flowback fluids and other oil and gas waste fluids are not present in concentrations that may affect human health.
- Municipal water authorities downstream of this outfall should be notified of the contaminants found in effluent from the PBT- Josephine Facility, of other possible contaminants in Marcellus Shale flowback fluids and oil and gas wastewater, and that there are other treatment facilities and POTW's in the Blacklick, Conemaugh, and Kiskiminetas drainages that accept and discharge oil and gas waste fluids into surface water. They should also be notified that landfill facilities in the drainage accept solid wastes produced from these treatment facilities. Downstream municipal water authorities should test raw

unfinished intake water and finished drinking water for identified contaminants in effluent from the PBT- Josephine Facility, and other contaminants known to be present in Marcellus Shale flowback fluids and oil and gas wastewater.

- All municipal water authorities at reasonable distances downstream of "brine treatment" and POTW's accepting Marcellus Shale flowback fluids and other oil and gas wastewater in the region extending eastward across Ohio, Pennsylvania and West Virginia and New York should be notified of these results. It is important that they initiate sampling of raw, unfinished inflow water and finished drinking water immediately to insure that their systems are capable of handling all potential contaminants, without breakthrough above specific drinking water MCL's.
- The PA DEP and other states and federal regulatory authorities, including the Susquehanna River Basin Commission (SRBC) and the Delaware River Basin Commission (DRBC) should immediately review all surface water discharge permits granted to brine treatment facilities and POTW's that accept Marcellus Shale flowback fluids and oil and gas wastewater, to insure that 2-BE concentrations being discharged are below all applicable standard, guidelines and criteria. This review should be informed by results of this report but should be extended to all known contaminants in flowback and other oil and gas wastewater.



Senate Committee on Environment and Public Works and its Subcommittee on Water and Wildlife

Joint Hearing "Natural Gas Drilling, Public Health and Environmental Impacts"

Testimony of Conrad Daniel Volz, DrPH, MPH
Graduate Faculty; Graduate School of Public Health, University of Pittsburgh
Director & Principal Investigator, Center for Healthy Environments and Communities (CHEC); Assistant Professor of Law (Secondary Appointment)

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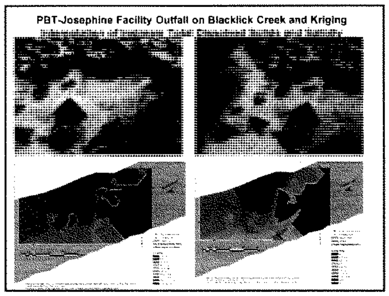
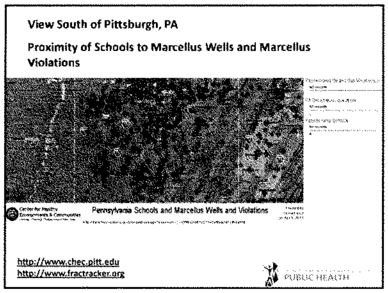
PUBLIC HEALTH



PBT-Josephine Facility Outfall on Blacklick Creek and Kriging



View South of Pittsburgh, PA

Proximity of Schools to Marcellus Wells and Marcellus Violations

Pennsylvania Schools and Marcellus Wells and Violations

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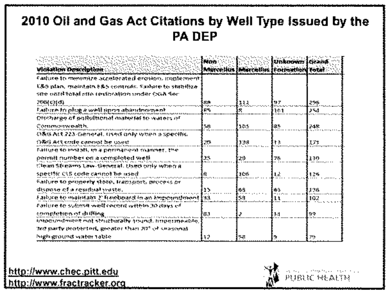

2010 Oil and Gas Act Citations by Well Type Issued by the PA DEP

Violation Description	Non Marcellus	Marcellus	Unknown Formation	Grand Total
Failure to minimize accelerated erosion, implement E&S plan, maintain E&S controls. Failure to stabilize site until total site restoration under OGA Sec 206(c)(d)	88	111	97	296
Failure to plug a well upon abandonment	85	8	161	254
Discharge of pollutional material to waters of Commonwealth.	58	105	85	248
O&G Act 223-General. Used only when a specific O&G Act code cannot be used	20	138	13	171
Failure to install, in a permanent manner, the permit number on a completed well	25	29	76	130
Clean Streams Law-General. Used only when a specific CLS code cannot be used	8	106	12	126
Failure to properly store, transport, process or dispose of a residual waste.	15	68	43	126
Failure to maintain 2' freeboard in an impoundment	33	58	11	102
Failure to submit well record within 30 days of completion of drilling	83	2	14	99
Impoundment not structurally sound, impermeable, 3rd party protected, greater than 20" of seasonal high ground water table	12	58	9	79

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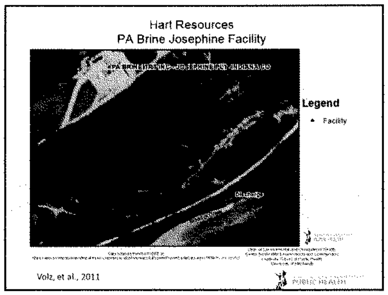
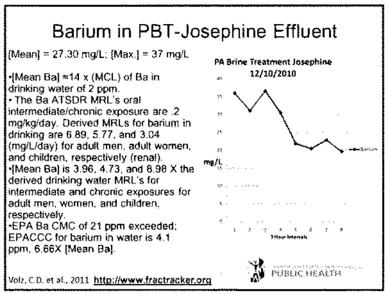


Hart Resources
PA Brine Josephine Facility

Volz, et al., 2011

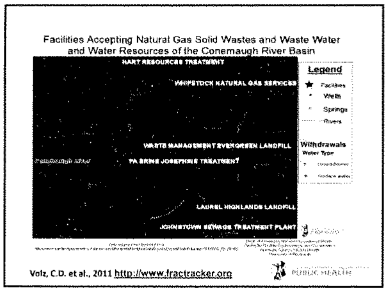


Barium in PBT-Josephine Effluent

[Mean] = 27.30 mg/L; [Max.] = 37 mg/L

- [Mean Ba] ≈14 x (MCL) of Ba in drinking water of 2 ppm.
- The Ba ATSDR MRL's oral intermediate/chronic exposure are .2 mg/kg/day. Derived MRLs for barium in drinking are 6.89, 5.77, and 3.04 (mg/L/day) for adult men, adult women, and children, respectively (renal).
- [Mean Ba] is 3.96, 4.73, and 8.98 X the derived drinking water MRL's for intermediate and chronic exposures for adult men, women, and children, respectively.
- EPA Ba CMC of 21 ppm exceeded; EPACCC for barium in water is 4.1 ppm, 6.66X [Mean Ba].

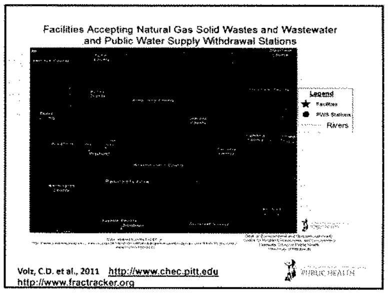
Volz, C.D. et al., 2011 http://www.fractracker.org



Facilities Accepting Natural Gas Solid Wastes and Waste Water and Water Resources of the Conemaugh River Basin

HART RESOURCES TREATMENT
WHIPSTOCK NATURAL GAS SERVICES
WASTE MANAGEMENT EVERGREEN LANDFILL
PA BRINE JOSEPHINE TREATMENT
LAUREL HIGHLANDS LANDFILL
JOHNSTOWN SEWAGE TREATMENT PLANT
Legend
Facilities
Wells
Springs
Rivers
Withdrawals
Water Type

Volz, C.D. et al., 2011 http://www.fractracker.org



Facilities Accepting Natural Gas Solid Wastes and Wastewater and Public Water Supply Withdrawal Stations

Volz, C.D. et al., 2011 http://www.chec.pitt.edu
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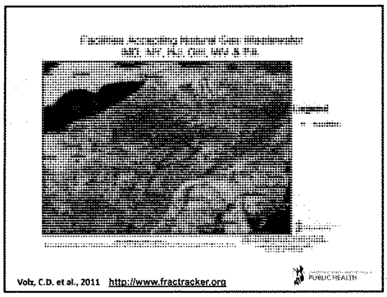

Volz, C.D. et al., 2011 http://www.fractracker.org

Senator CARDIN. Thank you very much for your testimony.
Mr. Ubinger.

STATEMENT OF JACK UBINGER, SENIOR VICE PRESIDENT, PENNSYLVANIA ENVIRONMENTAL COUNCIL

Mr. UBINGER. Thank you, Chairwoman Boxer, Chairman Cardin, Ranking Member Inhofe and Ranking Member Sessions for the opportunity to present testimony on behalf of the Pennsylvania Environmental Council concerning our work relating to shale gas development in Pennsylvania.

It goes without saying, and a number of the Members have already spoken to this, that there are enormous economic and strategic energy implications to the development of the shale gas resource. But as you have all been quick to add, it must be done right.

Pennsylvania's participation in the Nation's shale gas boom is relatively recent. It has occurred over the past 5 years with the development of the Marcellus Shale formation. As the statistics cited in our written testimony suggest, the development of the Marcellus Shale gas formation in Pennsylvania has increased at an ever-quickening pace and is expected to continue to do so.

While we in Pennsylvania appreciate the positive energy and economic attributes of shale gas development, we are also cognizant that throughout its history, Penns Woods has paid an enormous price for the exploitation of its bountiful natural resources.

In today's political discourse in many contexts, much is said about the burden that our current actions will impose upon future generations to come. Today in Pennsylvania when it comes to the legacy of natural resource exploitation, we are that future generation and the costs of restoration of degradation to our environment from prior resource exploitation is substantial.

If the lessons of the past have taught us anything it is this. Now, while we are in the formative years of a shale gas industry, an industry that will be a prominent part of our landscape for generations to come, we must identify and quantify the impact to our land, our water, our air and our communities and establish a regulatory framework that mitigates those impacts to the greatest extent practicable so that avoidable environmental degradation is not part of our legacy to future generations.

The written testimony that we submitted to the committee staff last week describes our work over the past two and a half years and identifies a number of enhancements to Pennsylvania's preexisting regulatory structure which we believe are essential to the prudent management of shale gas development. I would welcome the opportunity to answer any questions the committee may have with respect to our written testimony.

However, what I would like to focus on at the moment is the issue of cumulative impacts and the question is: How do we efficiently acquire relevant information to objectively assess and mitigate the cumulative impacts of the variety of activities which are required to extract, process and move natural gas from wellhead to the market?

We believe that the elements of an efficient process for assessing and mitigating cumulative impacts are found in a program established by the Susquehanna River Basin Commission to regulate water withdrawals for hydraulic fracturing. SRBC implements a robust data collection program which predates the Marcellus Shale development in Pennsylvania. However, the SRBC data base, which is expanded to include more information from headwater areas of the Marcellus Shale regions of the river basin, is used to make informed decisions for the authorization of water withdrawals and informed decisions as to when the authorized withdrawals must be suspended to avoid adverse impacts. The key, we think, is that it is the routine collection of data.

Similar data base assessment programs are not currently feasible for assessing the cumulative impacts of other attributes of shale gas development such as discharges from the surface management of wastewater or air emissions from shale gas development activities because the capacity to collect relevant field data is not available.

The Pennsylvania Environmental Council firmly believes that shale gas development cannot be properly managed without an investment in the capacity to routinely measure cumulative impacts on an ongoing basis. We further believe that the Federal Government, as well as the State, has a vital role in establishing and funding a continuing research agenda that will enable the collection and evaluation of the data required to assess and mitigate cumulative impacts.

We also believe that it is vitally important that the shale gas industry and the government both at the Federal and State level collaborate on projects to develop and demonstrate through data best management practices to mitigate impacts and require the implementation of best management practices throughout through appropriate regulations.

In closing, let me reiterate. The successful development of shale gas resources is economically important to the States in which is occurs and strategically important to the country as a whole, but it is critical that we do it right.

The Pennsylvania Environmental Council has focused its efforts on the development of a regulatory program in Pennsylvania which is based on proactive information-driven processes designed to identify and quantify impacts, including cumulative impacts and to mitigate those impacts to the greatest extent possible through best management practices appropriately codified in the regulatory framework.

We believe that our recommendations for Pennsylvania can serve as a model for others in the regulation of unconventional natural gas development.

Once again, let me thank the committee for this opportunity to present our testimony.

[The prepared statement of Mr. Ubinger follows:]

pennsylvania environmental council

Marcellus Shale Development in Pennsylvania

Testimony of

John W. Ubinger, Jr.

Senior Vice President
Pennsylvania Environmental Council
before the
Committee on Environment and Public Works
United States Senate

April 12, 2011

Introduction

The Marcellus Shale is one of the largest unconventional on-shore gas deposits in the world. Estimated at between 250-500 trillion cubic feet of gas deep underground, the Marcellus Shale represents a natural gas supply that could meet America's energy needs for the next 50-80 years or more.

It is widely considered that the Marcellus Shale play offers an abundant fuel to help bridge the gap between today's energy portfolio and a future supply that reflects both a reduced carbon footprint and reduced dependence on foreign sources of energy.

There is both a national security interest as well as a private sector interest in this extraordinary resource, setting the stage for a truly unique opportunity for economic development, energy security, private sector profitability and public revenue generation.

The promise of this new industry comes at a critical time in our history, when bridge fuels to the future are desperately needed to help reduce our dependence on foreign sources of oil. At the same time, the recession has created a state budget in need of new sources of revenue. Additionally the prospect of new job creation from natural gas development and new industries attracted to Pennsylvania by a reliable natural gas supply comes at a critical time in our Commonwealth, as the unemployment rate in one-quarter of Pennsylvania remains at over ten percent.

Without question, the Marcellus Shale is a once-in-a-lifetime situation, and one that is already underway. The size and potential of the Marcellus has set off a "Pennsylvania Gas Rush," analogous to the California Gold Rush, the Texas oil boom and the discovery of oil on Alaska's North Slope.

But for all the excitement and promise of new economic opportunity, there are striking similarities to other energy resource development booms in Pennsylvania's history. Indeed, Pennsylvania has paid a very heavy price for the development of timber, coal and other extracted resources. That price has even yet to be fully paid and is evidenced by over 5,000 miles of polluted waterways, thousands of abandoned mines and oil and gas wells, decaying infrastructure, and economic devastation caused by poor planning and a short-sighted thirst for growth decades ago.

We need to learn from the mistakes of the past, apply them to the development of the Marcellus Shale, and make sure that we do everything possible to create a sustainable, thriving, and successful Pennsylvania Marcellus Shale economy that does not leave an environmental burden to future generations.

There is widespread agreement that "business as usual" in Marcellus Shale natural gas operations, as well as its current regulatory oversight, is not equal to the scale and scope of this development, and that simply applying conventional solutions to these significant challenges will result in adverse consequences to all stakeholders in the process.

The Pennsylvania Environmental Council (PEC) has taken the lead in bringing together representatives of communities, the natural gas development industry, government and environmental interest organizations in the spirit of finding a strategy that all sides can agree will accomplish three fundamental goals:

1. Enable the gas industry to prosper in the successful development of the Marcellus Shale and other deep shale gas plays in Pennsylvania;
2. Ensure that Pennsylvania benefits from the success of this industry, while preventing long-term costs; and
3. Protect people and the environment from adverse effects that result from the expansion of drilling operations.

To begin this dialogue, PEC held the Pennsylvania Marcellus Shale Policy Conference in Pittsburgh on May 3-4, 2010. The goal of this forum was to identify the key issues, challenges and opportunities in the effective and sustainable development of a Marcellus Shale gas industry in Pennsylvania.

From this conference, PEC produced a detailed report, "Developing the Marcellus Shale: Environmental Policy and Planning Recommendations for the Development of the Marcellus Shale Play in Pennsylvania" in July 2010.[1] This report represents PEC's findings and conclusions from that public dialogue, allowing for further research and analysis.

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[1] Available at http://www.pecpa.org/marcellus

The policy recommendations in the report were offered to serve as the basis for new legislation and regulation designed to identify a framework whereby this vast natural resource can be developed for the benefit of America's energy portfolio, the private sector, and key stakeholders, while at the same time safeguarding the future prosperity of communities and the natural environment in Pennsylvania for current and future generations to come.

Since that time, PEC has been actively engaged in meetings with the members of the gas industry, state regulators, local governments and other environmental organizations aimed at bringing consensus to this debate around PEC's fundamental objectives. We were selected to serve as one of four environmental interest organizations on Pennsylvania Gov. Corbett's Marcellus Shale Commission in recognition of the leadership role PEC has played in seeking to bring about effective legislation and regulatory changes that give state government the resources and authority to effectively safeguard the people and environment of Pennsylvania with laws that are relevant to the modern industry.

Our fundamental position is that development of the Marcellus Shale need not produce winners and losers. If done right, the industry, the people of Pennsylvania, and the environment can all benefit from the combined effects of government regulation that is equal to the task at hand and the enforcement of best management practices in an industry that has already demonstrated its capabilities in this regard. It is our hope and belief that Pennsylvania can be a model to the nation in sustainable energy development, and preserve the historic landscape of Pennsylvania's environment for future generations.

Impacts of Development in Pennsylvania

Over the past five years, the development of the Marcellus Shale gas formation in Pennsylvania has increased at an ever-quickening pace. It has transformed the stagnant natural gas industry in Pennsylvania and has significant implications in the energy market at both the national and perhaps the international scale. It has also affected local communities, particularly communities not accustomed to industrial scale activity, in both positive and negative ways.

Last year 3,314 permits were issued by the Department of Environmental Protection, and 1,446 wells were drilled for the Marcellus Shale formation. Permit approvals for 2011 are already outpacing last year's numbers. Some analysts estimate that over the next 10 years annual Marcellus Shale formation well drilling activity will steadily increase from 2,500 wells per year to over 3,500 wells per year.[2]

The projected development of the Marcellus Shale formation and the anticipated development of the Utica Shale and perhaps other shale formations in Pennsylvania means that we are in the formative years of an industry that will be a prominent part of the Pennsylvania landscape for multiple generations to come.

One of the challenges of unconventional gas development in Pennsylvania is the density of well development activities. Thus far, well development activities have been concentrated primarily in a handful of counties in the northern tier and in the southwest corner of the Commonwealth. With very limited exception,[3] this concentrated activity is occurring without gathering information that is needed to identify and assess the impacts of this activity. PEC believes that as the natural gas exploration, production and delivery infrastructure is developed in the rest of the Marcellus Shale play and in other shale gas formations in Pennsylvania, it is vitally important to systematically collect and compile a data base of relevant information that is publicly accessible. Such information is necessary to assess the impacts of the past activity as well as ongoing activity, and to establish adaptable requirements that are designed to mitigate impacts to the greatest extent possible both in the near term and the long term.

There are a number of studies being undertaken by organizations such as the Environmental Protection Agency, the Department of Energy National Energy Technology Laboratory and the Interstate Oil & Gas Compact Commission to identify impacts of shale gas development. In addition, we are aware that:

- The U.S. Environmental Protection Agency is conducting a study plan on the potential environmental and human health implications of hydraulic fracturing, with special emphasis on the relationship between hydraulic fracturing and drinking water resources;
- President Obama has asked the Department of Energy's Advisory Board to produce a report offering recommendations on how to assure that shale gas development does not adversely affect water quality; and

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[2] See Timothy J. Considine, et al, The Economics of the Pennsylvania Marcellus Shale Natural Gas Play: An Update, at 16, (The Pennsylvania State University, College of Earth and Mineral Sciences, Department of Energy and Mineral Engineering, May 24, 2010).

[3] In November 2010 the Pennsylvania Chapter of The Nature Conservancy published its first in a series of analyses on energy development impacts to Pennsylvania. This first report included an analysis of potential impacts from Marcellus Shale development.
The report is available at: http://www.nature.org/media/pa/pa_energy_assessment_report.pdf

- Last week the Chesapeake Bay Foundation petitioned the Council on Environmental Quality to conduct a multi-state Programmatic Environmental Impact Study examining the potential risks and possible cumulative impacts of natural gas development throughout the Marcellus Shale formation.

We are also aware that the state of New York has been engaged in a general environmental impact statement process relating specifically to unconventional wells developed by high volume hydraulic fracturing.

PEC's focus since the publication of our report has been the design of a model state-level regulatory and management process that operates on proactive, comprehensive information gathering and assessment prior to individual site development and well operation. In short, information gathering and assessment should be an integral part of the regulatory and permitting process. This basis then allows for adaptive management as greater understanding of this complex and dispersed activity – and its impacts – is developed.

Regulatory Challenges in Pennsylvania

Pennsylvania's regulatory framework as it existed five years ago was designed for shallow vertical wells that were far less complicated than horizontal shale gas wells. The production of natural gas from what are termed "unconventional" resources such as the Marcellus Shale formation is a much more complex set of operations. The nature of these operations, which include the use of high volume hydraulic fracturing, as well as greater associated infrastructure, equipment and transportation demands, significantly increase the potential for adverse impacts to terrestrial and aquatic resources. What's more, any industrial process is subject to failures of technology and human judgment.

Given the rapidly increasing deployment of Marcellus Shale activity, often occurring in either close proximity to communities or sensitive natural resources or both, the need to reform Pennsylvania's management program has been great. In response, the Department of Environmental Protection has effected critical changes to its oil and gas management program and successfully proposed new regulations for promulgation by the Pennsylvania Environmental Quality Board.

On the regulatory front, DEP formulated and directed two major regulations through the Environmental Quality Board rulemaking process in the past two years:

- Regulatory amendments made to 25 Pa. Code Chapter 78[4] that significantly strengthen well casing and cementing standards to better ensure well integrity and protect against the migration of methane and hydraulic fracturing fluids. Insufficient well casing and completion has already proven to cause adverse impacts to private and public water supplies in Pennsylvania.

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[4] Pennsylvania Bulletin August 21, 2010 (40 Pa.B. 4835)

- Regulatory amendments made to 25 Pa. Code Chapter 95[5] that place stringent total dissolved solids (TDS) limits for the disposal of wastewater generated through unconventional shale gas development. These amendments have created strong economic incentive for the reuse of flowback fluids, helping to offset a still-significant water management challenge for Pennsylvania.

These vital changes will greatly contribute to better management of the industry and the avoidance of detrimental impacts.

But there remains much to be done, and we must acknowledge that the implementation of best management practices within the industry – beyond the point of regulation – are equally important to ensuring that unconventional shale gas development can provide economic growth and energy production without undue and long-term costs to the environment and people of Pennsylvania. At a minimum, this work must include:

- Ensuring that sufficient financial assurance is in place to address impacts if and when they arise. Currently Pennsylvania's bonding program is woefully inadequate in relation to the size and extent of unconventional shale gas operations.
- Enacting additional amendments to Pennsylvania's Oil & Gas Act to provide the Department of Environmental Protection with more precise authority to protect public and natural resources in the permitting and enforcement process.
- Enhancing Pennsylvania's Natural Heritage Program to better accommodate more regional or comprehensive planning by state resource agencies and the industry; as opposed to segmented, site-by-site analysis.
- Ensuring that sufficient funding is consistently provided to Pennsylvania's resource protection agencies so they may adequately perform their statutorily-mandated responsibilities. During the last several years, our state resource agencies have experienced the greatest burden of budget cuts and staffing reductions.[6]
- Ensuring better and more consistent management of water use in unconventional shale gas operations across Pennsylvania, including more comprehensive accounting and analysis of potential aquatic resource impacts.
- A restructuring of the overall permitting process which provides more robust and effective informational collection and assessment prior to the commencement of individual well operations.

We sincerely believe these objectives can be accomplished in a manner that is equally protective of the environment and public as it is supportive of the industry. We would like to address the latter two items in a bit more detail to highlight the nature of this challenge as well as how the objectives of PEC's work can better inform management efforts.

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[5] Pennsylvania Bulletin February 5, 2011 (41 Pa.B. 805)

[6] One notable exception has been the Department of Environmental Protection's concerted effort in adding Oil and Gas Bureau field staff to monitor Marcellus Shale activity over the past several years. However, imposed budget cuts continue to significantly affect other Department Bureaus and Programs, many of which have a role to play in overall management of this escalating activity.

Water Management

Current estimates place water demands for hydraulic fracturing at three to five million gallons per well. While the demands of unconventional shale gas development may be less than those of other industrial or energy producing activities, the fact remains that unconventional shale gas development is more likely to occur in remote locations where water withdrawals from smaller or high quality streams can quickly have significant cumulative impacts. Thus, the need for consistent and effective management across Pennsylvania is critical.

Yet management of water use for Marcellus Shale operations in Pennsylvania is a matter of geography. If a proposed water withdrawal is made in the Susquehanna or Delaware River Basins, it will be subject to the respective regulatory programs of the Susquehanna or Delaware River Basin Commissions. While the Susquehanna River Basin Commission has a robust water management program for Marcellus Shale operations, the Delaware River Basin Commission has imposed a moratorium while it works to update its regulations in response to growth of the industry.

In the Ohio River Basin, which does not have a corresponding Commission in place with water quantity authority, the Department of Environmental Protection has developed a Water Management Plan component as part of the well operation permitting process. The Department requires this submission through extension of existing authority via the Pennsylvania Clean Streams Law.[7]

The division of water management responsibility is unavoidable given that the River Basin Commissions are rightly acting pursuant to interstate compacts. The challenge is now before the Department and River Basin Commissions to work together to determine how water quantity issues can be best addressed, and to establish exemplary and consistent protocols and best management practices throughout Pennsylvania.[8]

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[7] Pa. Stat. Ann. Tit. 35, §691.1 et seq. The Clean Streams Law does not directly provide for regulation of water withdrawals. Rather its focus is on activities that cause or may cause "pollution" (broadly defined to include physical, chemical or biological alteration) to waters of the Commonwealth. *See generally* R. Timothy Weston, *Water and Wastewater Issues*, Prepared for the 2011 Penn State Marcellus Shale Law and Policy Symposium (February 10, 2011). One of the recommendations of PEC's report is to provide clear statutory authority for the Department to manage large scale water withdrawals.

[8] The program established by the Susquehanna River Basin Commission is frequently cited as a model for how effective management with strong informational reporting can be performed without unduly affecting the industry.

Permitting

As indicated previously, Pennsylvania's regulatory framework for natural gas exploration and production, as it existed at the onset of the Marcellus Shale boom in 2005, did not contemplate the scale and intensity of horizontal unconventional well development activities. It was designed for conventional reservoir formation vertical wells which required limited, if any stimulation by hydraulic fracturing.

The Department of Environmental Protection has responded to some of the identified deficiencies in the conventional permitting framework through administrative alterations to the application process; the development of proposed amendments to oil and gas regulations and water quality standards which were promulgated by the Pennsylvania Environmental Quality Board; and other actions to increase the capacity to review applications and monitor well development activities. However, PEC believes that a more fundamental change in the permitting process is required because the existing process does not provide for the acquisition of sufficient information to make well-informed well pad siting decisions.

Based on discussions with unconventional gas exploration and development companies, we have the sense that some of the companies voluntarily implement sophisticated well pad siting processes that go beyond the minimum requirements in the current application process, involve meaningful engagement with surface property owners and the community, and are intended to mitigate potential impacts to the greatest extent reasonably possible. However, we also have the sense that the attitude and effort level of the sector as a whole varies widely.

Later this month PEC will present a package of proposed amendments to the Pennsylvania Oil and Gas Act, which will include a section that will fundamentally alter the existing permit application process. The revised application process is designed to gather more information on site conditions and focus more attention on the siting of well pads and associated infrastructure. Generally speaking, we will advocate that the permit application process for unconventional wells involving development by high volume hydraulic fracturing be split into two distinct phases. The first phase will be limited to the identification and assessment of site conditions for the purpose of determining whether a well pad should be authorized and, if so, the siting conditions that must be taken into account for selecting the precise location of the well pad and ancillary infrastructure. The second phase will focus on construction authorization of the well pad and the drilling, casing and development of the wells.

We believe that the two phase approach will allow for more flexibility in the siting of well pads to minimize risk and reduce the surface impacts of well pads and ancillary facilities to the greatest extent possible. At the same time, because the siting of the well pad will be pre-approved in the Phase I process, the Phase II application process should be at least as time-efficient, if not more efficient, than the current process. Consequently, once a well developer has assembled a portfolio of approved sites through the Phase I authorization process, it should have the necessary flexibility in planning rig movement.

In developing our proposal, we are cognizant of the interest that the process be reasonably predictable in terms of the level of effort required by the well developer to complete applications and the amount of time required to process pending applications. We believe that the two-phase process can be structured and implemented in a manner that will not unduly interfere with efficient well development.

Beyond Pennsylvania

As you can see, the breadth of issues in Pennsylvania is daunting, and our state is only one of many experiencing shale gas development. While we have found lessons learned and actions taken in other states to be instructive to our own work on these issues, they are tempered by the fact that Pennsylvania's topography, geology and climate are very different from places like Texas, Alabama, and Colorado. For this reason we believe that efforts to improve management and oversight of the industry should be primarily directed at the state level.

But that obviously does not and should not preclude the federal government from continuing its strong oversight of any shale gas state, including Pennsylvania. In fact, for some of the same reasons addressed before in this testimony – including the very real struggles of state agencies to meet existing state and federal mandates due to budgetary constraints – we believe federal engagement is essential.

Consistent with our principle of adaptive management, as information develops and if better understanding of individual and cumulative impacts point toward the need for revision of federal statues or regulations, we would urge swift and appropriate action. As Pennsylvania has learned first hand, environmental legacies from improperly controlled resource development is extraordinarily costly and detrimental to economic vitality and public well being. Even today Pennsylvania faces abandoned mine remediation costs that well exceed one billion dollars, and must account for thousands of miles of rivers and streams which fail to meet water quality standards because of acid mine drainage.

With the ongoing growth of the unconventional shale gas activity, we don't have a moment to lose in getting it right.

Conclusion

The oil and gas regulatory structure in Pennsylvania did not contemplate horizontal drilling in combination with high volume hydraulic fracturing and is not adequate to manage the escalating development of Marcellus Shale development throughout Pennsylvania. The current regulations are not designed to obtain timely and sufficient information to make well-informed decisions concerning the siting of well pads or to build a database identifying cumulative impacts of well development activities on the scale projected by the oil and gas industry. The natural gas industry has made great strides in leading innovation, but the regulatory framework must address the complexities created by the pressure of time, scale, cost and technology.

Given the extraordinary opportunities and challenges associated with Marcellus Shale gas extraction, it is incumbent upon key stakeholders to take whatever steps are necessary to ensure the safe and reliable development of this resource in a way that does not repeat the mistakes of the past.

Throughout Pennsylvania's history, our natural resources have been exploited for industrial purposes without the benefit of careful consideration and forethought. The price paid in exchange for this rapaciousness can never be fully calculated, yet remains evident in the forests, waterways, and communities and that cost has been shouldered by generations that followed the development.

More recently, accidents at drilling rigs have captured the attention of the news media, regulators and Pennsylvania citizens. These incidents cannot and should not be ignored – they highlight the need for prompt and effective reform.

The spot market for natural gas is considered to be temporarily undervalued, with gas prices of approximately $4.25 per million cubic feet. Even at that low price, the Marcellus Shale represents a natural resource whose development can be valued at $1-2 billion in Pennsylvania. Considered in this context, PEC urges that a long-term view of development be adopted which allows all stakeholders to realize the benefits of the resource while safeguarding the health and safety of our citizens and the environment that has still not yet fully recovered from past resource development movements.

Pennsylvania has an extraordinary opportunity to enact the nation's best body of laws governing the extraction of a vast natural resource. Such action would effectively legislate the nation's best practices and make them the standard by which the Marcellus Shale is developed and provides the benefits to the Commonwealth that have been heralded as the promise of this new industry.

Environment and Public Works Committee Hearing
April 12, 2011
Follow-Up Questions for Written Submission

Response of John W. Ubinger, Jr.
Senior Vice President
Pennsylvania Environmental Council

May 17, 2011

Prefatory Response

On May 10, 2011, the Pennsylvania Environmental Council and the Chesapeake Bay Foundation presented an outline of legislative amendments to reform Pennsylvania's Oil and Gas Act to the Pennsylvania Marcellus Shale Advisory Commission. The primary objectives of the "Marcellus Shale Amendments" are to: (1) reform the permit application process to facilitate greater stakeholder input and site analysis; and (2) set clear and appropriate protection standards in light of the hydraulic fracturing practice and the degree of infrastructure required for shale gas extraction. The Marcellus Shale Amendments include elements which address some of the questions posed by Senator Boxer and Senator Cardin; therefore, we have attached our Marcellus Shale Amendments outline to this response.

Questions from:
Senator Barbara Boxer

1. The Pennsylvania Environmental Council (PEC) released a report last year with policy recommendations on Marcellus Shale development. One of the recommendations is to require an advanced planning process for natural gas development in Pennsylvania, which would identify and assess siting issues before a drilling permit is issued.

Could you please explain more about what kinds of siting issues should be considered during this process? Do you think that this review should take into account potential cumulative impacts of the proposed well on human health and the environment in the surrounding area?

Response

Part Two of the of the attached Marcellus Shale Amendments outline (page 4) describes our proposal for restructuring the permit application process for unconventional natural gas wells developed by high volume hydraulic fracturing. The application process would be bifurcated into two distinct phases: Phase I which is focused on the approval of the location of the well pad and ancillary infrastructure ("Well Site") and Phase II which is focused on the approval of the well development process. The foundation of the Phase I approval is a more thorough site assessment process which includes the proactive solicitation of relevant information from stakeholders such as local property owners, municipal and county governments, "Water Purveyors," and other entities such as the Pennsylvania Fish and Boat Commission, the Pennsylvania Game Commission and County Conservation Districts. Another feature of the Phase I permit process is the performance of an alternatives analysis which demonstrates: (1) that options to avoid or minimize surface disturbances, forest fragmentation and other impacts on natural resources have been identified and evaluated; and (2) that the potential use of pre-existing infrastructure (*e.g.* access roads, water supply facilities, gathering lines, and compressor stations) have been taken into account to mitigate cumulative impacts.

Our Marcellus Shale Amendments include some of the site assessment specifications which should be included in the Phase I approval process; however, the final specifications should be developed as technical guidance by the Department of Environmental Protection with input from interested stakeholders and professionals with the relevant technical knowledge and experience. We specifically recommend technical guidance rather than regulations so that the specifications can be readily adapted as best practices continue to evolve.

The identification, assessment and mitigation of cumulative impacts are among the most challenging aspects of the regulation of shale gas development. We believe that the proposed Phase I permit approval process will have some mitigating effects on cumulative impacts; however, as pointed out on page 2 of the Marcellus Shale Amendments outline, it may be necessary to develop a framework for regional planning outside of the provisions of the Oil and Gas Act. PEC continues to be engaged in the development of a solution to this challenge. Some of the concepts under consideration by PEC and others are identified on page 11 of the Marcellus Shale Amendments outline.

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2. In your report, PEC recommended that the level of site specific information that should be required prior to the issuance of a permit for hydraulic fracturing should be based on an "all appropriate inquiry" (AAI) standard, similar to the AAI standard developed as part of the of the federal brownfields redevelopment program under section 101(35)(B) of the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA). Your report further stated that not all of the specific elements of the CERCLA AAI standard should be made applicable to the natural gas well development scenario, but that "a number of the elements, if properly adapted, should be incorporated into a site-specific information gathering process."

Could you explain which specific elements of the CERCLA AAI standard should apply, how those standards should be adapted, and what additional elements does PEC recommend be part of the natural gas well AAI standard?

What process should be used to develop a natural gas well AAI standard?

Response

The reference to the CERCLA "all appropriate inquiry" standard in PEC's July 2010 Marcellus Shale Policy Recommendations report was principally intended to show that a context-specific site assessment standard had been developed for contaminated sites. Candidly, at this point in time, PEC has not engaged in a specific review of the details of the CERCLA all appropriate inquiry standard to a degree which would enable us to respond to the question as posed. Our categorical thoughts about the elements of an all appropriate inquiry for potential well site assessments are set forth on page 18 of the July 2010 Report and in the description of the Phase I permit approval process in the Marcellus Shale Amendments outline attached to this response.

As indicated previously, PEC does not profess to have the technical knowledge and experience to prescribe the details of the appropriate inquiry for well site assessments. We believe that the all appropriate site assessment protocol should be developed through a stakeholder process and published as technical guidance. In the first instance, this process can be convened by Pennsylvania DEP. Ultimately, a further development of the site assessment protocol could be undertaken by a recognized standard development organization such as ASTM International which has developed commonly accepted standards for site assessments. (See, *e.g.*, ASTM E 2247 – 08: "Standard Practice for Environmental Site Assessments: Phase I Environmental Site Assessment Process for Forestland or Rural Property.")

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Questions from
Senator Benjamin L. Cardin

1. Industry representatives often claim that there is no documented instance of water contamination from hydraulic fracturing. However, this claim is often based on a narrow interpretation of the term "hydraulic fracturing," focusing on the horizontal drilling itself rather than the life cycle of the process. Which do you feel is the appropriate lens from which to view the environmental impacts of hydraulic fracturing?

Response

Those who promote the use of hydraulic fracturing to produce gas from the Marcellus Shale formation and other unconventional shale gas formations often state that there has never been a recorded incident of groundwater contamination from hydraulic fracturing. Those who are opposed to the use of hydraulic fracturing methodology state, or infer, that groundwater contamination routinely occurs as a consequence of hydraulic fracturing.

When framed in the manner stated above, the discourse lacks a common definition of what the hydraulic fracturing process entails. The hydraulic fracturing process involves the high pressure injection of several million gallons of water containing a "proppant" (typically silica sand) and a small percentage of some number of chemical additives into the shale formation; the fracturing of the shale formation; and the management of the so-called "flow back" water at the surface. The industry's reported experience in Pennsylvania is that 10 to 20 percent of the injected water returns to the surface during the hydraulic fracturing process as flow back water. Additional amounts of the injected water return over time, during the production phase of the well, as "produced water." As we understand it, there is no evidence that the fracturing process *in the Marcellus Shale formation* (*i.e.*, the horizontal segment of a shale gas well) has caused groundwater contamination by migration through natural pathways from the Marcellus Shale formation to a water supply groundwater unit, because of the depth of the formation and the geologic separation of the shale formation from groundwater units suitable for water supply. However there is evidence of groundwater and surface water contamination from the injection process due to casing and cementing failures in the vertical segment of the well, loss of well control, and from flow back water when it is not carefully managed on the surface.

In order to have constructive dialogue on the potential cause-and-effect relationship of hydraulic fracturing and groundwater or surface water contamination we believe that the questions to be asked and answered should be directed to the specific operations involved in the hydraulic fracturing process, *i.e.* the injection of hydraulic fracturing water and recovery of flow back water through the vertical segment of the well; the fracturing of the shale formation through the horizontal segment of the well; and the management of flow back water and produced water on the surface. We suggest that the properly framed questions include the following:

- How many cases of groundwater contamination caused by the injection of hydraulic fracturing fluid or the recovery of flow back water have been recorded?

- What was the cause of the contamination: design failure; equipment failure, casing and cementing failure; or human error?

- What is the performance record for unconventional shale gas wells constructed to meet a design standard equivalent to the new casing and cementing standard promulgated by the Pennsylvania Environmental Quality Board in 2010 (effective February 5, 2011)?

- Can it be confirmed that there has not been an occurrence of groundwater contamination caused by contaminants migrating from the Marcellus Shale formation through naturally occurring pathways following hydraulic fracturing?

- Is there a reasonable need for a long-term monitoring study to determine the fate and transport of hydraulic fracturing fluids which are not recovered as flow back water or produced water? If so, how should the study be designed; who should perform the study; and how should it be funded?

- What are the demonstrated best management practices for the prevention of surface releases of flow back water or produced water?

Answers to questions such as those suggested above, as well as additional questions that may be framed, should be obtained through the routine, long-term collection of data which is made readily available to regulators, and the public. The answers to these questions should be the foundation for the formulation of regulatory proposals to codify best management practices as well as a framework for the routine, long-term monitoring of compliance and sanctions against noncompliance.

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2. In areas where there has been oil and gas drilling in the past, there are often orphaned wells - wells that are abandoned and unplugged, with no responsible party. However, due to imprecise record-keeping, the amount of such wells and their locations are often unknown. For example, Pennsylvania regulators estimate that there are over 100,000 orphaned wells in the state, and only 197 wells have been plugged so far.
Can orphaned or abandoned wells within the drilling area increase the likelihood of water contamination by providing pathways for fracking fluids and produced water to migrate? Do abandoned or inoperable underground coal mines present a similar risk?

Response

Our understanding from review of literature and discussions with geologists and hydrogeologists is that unplugged oil and gas wells can serve as a preferential pathway for the transport of fluids and migration of methane. We assume that subsurface disturbances from prior mining activities may also serve as a preferential pathway for fluids and may also be the source of biogenic methane.

One of the objectives of the Phase I permit approval process included in our Marcellus Shale Amendments is to increase the probability of identifying site conditions caused by prior uses, including undocumented oil and gas extraction or coal mining. A more thorough understanding of site conditions will enable potential preferential pathways to be identified and avoided. Additionally, our July 2010 Marcellus Shale Policy recommendations (page 19) include the proposition that the identification of orphan unplugged oil and gas wells through our proposed site assessment process can become the catalyst for a program to accelerate the orphan well plugging program in Pennsylvania.

***

3. In your testimony, you note the importance of systematically collecting and compiling data that will allow policymakers the ability to assess the impacts of past and ongoing

activity related to natural gas drilling. The Chesapeake Bay Foundation recently filed a citizen petition requesting the completion of a programmatic environmental impact statement addressing the cumulative impacts of drilling in the Marcellus Shale formation. Would the completion of a programmatic environmental impact statement constitute the kind of systematic data compilation you feel would be helpful to encourage adaptive management of these issues?

Response

The statement in our testimony concerning the importance of systematically collecting and compiling data to allow policymakers to assess the impacts of past and ongoing activities related to natural gas drilling was made in relation to the long-term, routine data collection program employed by the Susquehanna River Basin Commission (SRBC). SRBC's systematic field data collection program, which predates the emergence of Marcellus Shale development and has been enhanced to account for shale gas development, enables SRBC to make well-informed judgments concerning the authorization of water withdrawals and, equally important, to determine when it is necessary to limit new authorizations or suspend existing withdrawal authorizations to avoid unacceptable cumulative impacts. PEC believes that it is critically important to routinely collect field data to establish baseline conditions; monitor well development activities, including the performance of best management practices, and to assess the cumulative impacts of well development activities. These data collection activities should occur routinely throughout duration of the shale gas development activities.

As we understand it, the "programmatic environmental impact statement" sought by the Chesapeake Bay Foundation would be a finite assessment of existing information rather than an ongoing, long-term data collection and assessment program. As such, it would serve a different purpose than the data collection program which PEC has proposed.

***

Developing the Marcellus Shale

Environmental Policy and Planning Recommendations for the Development of the Marcellus Shale Play in Pennsylvania

A Report of
Findings and Recommendations

Based on:

The Pennsylvania Marcellus Shale Policy Conference
Pittsburgh, Pennsylvania

pennsylvania environmental council

July 2010

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Developing the Marcellus Shale

Environmental Policy and Planning Recommendations for the Development of the Marcellus Shale Play in Pennsylvania

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DISCLAIMER

This report contains the recommendations of the Pennsylvania Environmental Council following the Marcellus Shale Policy Conference. While this conference event was co-sponsored by Duquesne University, they were not a contributor to this report nor have they endorsed the recommendations contained herein.

We also wish to emphasize that these recommendations do not represent any consensus by participants at the conference.

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PREFACE

About the Report

The Marcellus Shale natural gas reserve represents an extraordinary environmental and economic opportunity – and challenge – for Pennsylvania. Without question, this is a once-in-a-lifetime situation, and one that is already underway.

There is general consensus that "business as usual" in Marcellus Shale natural gas operations, as well as its current regulatory oversight, is not equal to the scale and scope of this development, and that simply applying conventional solutions to these significant challenges will result in adverse consequences to all stakeholders in the process.

For this reason, the Pennsylvania Environmental Council (PEC) and Duquesne University co-sponsored the Pennsylvania Marcellus Shale Policy Conference (the "Conference") in Pittsburgh on May 3-4, 2010. This forum brought together key stakeholders, regulators, industry officials, environmental advocates, civic and municipal leaders, and others to engage in a public participation dialogue. The goal of this process was to identify the key issues, challenges and opportunities in the effective and sustainable development of a Marcellus Shale gas industry in Pennsylvania.

The Marcellus Shale natural gas reserve arguably represents the largest environmental and economic opportunity–and challenge–for Pennsylvania.

This report represents PEC's findings and conclusions from that public dialogue, allowing for further research and analysis. We note that these recommendations are not intended to represent any consensus positions taken by participants at the Conference.

The policy recommendations contained herein are intended to serve as the basis for new legislation and regulation designed to identify a framework whereby this vast natural resource can be developed for the benefit of America's energy portfolio, the private sector, and key stakeholders, while at the same time safeguarding the future prosperity of communities and the natural environment in Pennsylvania for current and future generations to come.

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Why We Must "Get It Right": Energy in America and Pennsylvania's Historical Legacy

Pennsylvania has long been rich in the natural resources needed for energy, industrial growth and economic expansion in America.

From colonial times, the Commonwealth's abundant timber and subsequently discovered coal, oil and gas reserves were readily harvested to provide fuel, building materials and raw material critical to the Industrial Revolution. The bounty of such resources seemed endless at the time, and gave rise to an insatiable appetite for consumption.

The history of Pennsylvania's role in America's Industrial Revolution is well documented. At the same time the legacy of the environmental degradation is readily apparent; both in the landscape of the Commonwealth, and the continuing expenditure of substantial public funds for the mitigation of threats to health and safety and the restoration of degraded land and water. There is much said in the current political discourse about the burden that we are imposing on future generations, just as we are part of the "future generation" that has inherited the burden of the environmental legacy of the Industrial Revolution.

Prior to the colonization of Pennsylvania, it was estimated that "Penn's Woods" covered nearly 90 percent of the Commonwealth.[1] In the nineteenth century, Pennsylvania welcomed the logging industry which provided lumber and timber for building towns, cities and railroads all over the eastern United States.[2] By the 1920s Pennsylvania had lost approximately 60 percent of its forest land, leaving barren landscapes devastated by erosion and wildfires.[3] A century after the establishment of the Forestry Commission of Pennsylvania in 1893, 60 percent of the Commonwealth is forest land once again.[4]

From the outset of the Industrial Revolution, coal extraction was humming at a fever pace at the surface and deep beneath the ground. Coal was "king", for use as both an energy source and a feedstock for the steel industry. Widespread coal consumption left a trail of environmental devastation in its path – first in air quality, and later in acidic waterways and scarred landscapes all over Pennsylvania. Even today, 5,510 miles of streams throughout the Commonwealth are so heavily polluted from mine drainage that it will take at least several more generations for their natural condition to be restored.

The exploitation of the Commonwealth's oil and gas reservoirs began in the middle of the nineteenth century. According to the Pennsylvania Department of Environmental Protection (DEP), as many as 350,000 oil and gas wells have been drilled in the Commonwealth since Col. Edwin Drake drilled the

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first oil well here near Titusville in 1859. Drilling permits for new oil and gas wells were not required until 1956, and the requirement to register existing wells was not instituted until 1985.[5] The status of many wells drilled and abandoned before the institution of permitting and registration requirements is unknown; DEP estimates that more than one-half of the wells drilled in the Commonwealth (approximately 184,000 wells) are unknown as to location and status.[6]

Indeed, Pennsylvania's rich history has been paralleled by its unique role in America's energy future. Wood, coal, petroleum, and natural gas have all been rooted in Pennsylvania's industrial past and have been inextricably linked to the natural environment that so inspired America's forefathers centuries ago. And Penn's Woods has paid an enormous price for the development of those energy resources – a price that has taken generations and untold fortunes to recover from. That recovery is far from over.

If the lessons from Pennsylvania's historic past have taught us anything, it's that we cannot allow such a price to be levied on future generations ever again.

The Marcellus Shale

The Pennsylvania Marcellus Shale reserve is one of the most significant domestic energy discoveries in decades. With somewhere between 250 and 500 trillion cubic feet of natural gas, the Marcellus Shale formation is one of the largest unconventional on-shore gas deposits in the world.

Conservative estimates of the available reserves contained in Pennsylvania alone indicate that there is at least a 40 to 50 year supply of natural gas available for near-term extraction. Other estimates set the supply at as much as 80 years or more. Deeper formations, including the Utica Shale, could extend the deep shale extraction period into the next century.

It is widely considered that the Marcellus Shale play offers an abundant fuel to help bridge the gap between today's energy portfolio and a future supply that reflects both a reduced carbon footprint and reduced dependence on foreign sources of energy.

There is both a national security interest as well as a private sector interest in this extraordinary resource, setting the stage for a truly unique opportunity for economic development, energy security, private sector profitability and public revenue generation.

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At the same time, however, it's important to understand that the horizontal drilling and extraction methods needed to develop deep shale are inherently more complex than conventional methods. The ability to produce natural gas from deep shale formations such as the Marcellus Shale at an economic scale is the result of a relatively recent, innovative combination of technologies that enable deep horizontal drilling and hydraulic fracturing of shale formations to extract natural gas. (Wells developed by employing hydraulic fracturing, or "fracking," to stimulate the extraction of gas from the formation are commonly referred to as "unconventional wells.") The fracking component of Marcellus Shale formation well development involves the high-pressure injection of three to five million gallons (on average) of water treated with certain chemical additives as well as the on-site management of this injected "frack water," which is commonly referred to as "flowback" water. Frack water may also return to the surface over a longer period of time as a component of "produced" water.

The mechanical and technical requirements of drilling and gas operations at unconventional Marcellus Shale wells are more costly and intricate, and have higher potential risk than conventional extraction efforts typically employed in the past. The recent devastation caused by offshore drilling in the Gulf of Mexico (April 2010) is a reminder that using complex technologies in oil and gas extraction can sometimes have consequences that are destructive, costly and even deadly.

In Pennsylvania, there already have been incidents involving water supply well contamination, a fire in an onsite flowback impoundment, and a well blowout during the fracking process which resulted in the off-site release of frack water. There are also concerns regarding forest fragmentation and other adverse environmental and local community impacts arising from the scale of activities required to develop an unconventional deep shale formation well.

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The Promise of a New Industry

Developed with discretion and foresight, the Marcellus Shale can hold the promise of "once in a generation" benefits for Pennsylvania.

- ***Industry*** – This formation has already proven to be the most significant new opportunity in the gas industry since the Barnett Shale discovery in Texas a decade ago. According to the industry,[7] the Barnett Shale play is estimated to account for 8% of the total economic output of the Fort Worth region and more than 83,000 jobs. The same estimates place generated tax revenues (direct and indirect) at more than $715 million for the State of Texas, resulting in $10 billion in economic activity. As the pace of Marcellus Shale development increases over time, the economic impact throughout Pennsylvania may rival or even exceed that of the Barnett Shale region in Texas.

- ***State Government*** – At the same time, revenues to the state – ranging from mineral lease payments and royalties on state land to direct and indirect tax revenue – comes at a time of state budget shortfalls and pressure to generate new sources of revenue. As of the publication of this report, the Commonwealth of Pennsylvania is contemplating a severance tax that would be applied to wellhead production on natural gas extraction operations statewide.

- ***Local Government*** – Arguably the greatest impact is on local government, for it is at the local level where job creation, economic development, as well as adverse impacts will be most profound. Just as the coal and steel industries gave rise to towns and municipalities throughout Pennsylvania, the Marcellus Shale industry will likely be transformative to many small, rural communities across the Commonwealth. Recent assessments have shown significant employment opportunities during natural gas well development; it remains to be seen, however, how many of the created jobs will be long-term, local employment opportunities.[8] In addition, without appropriate measures to account for the impacts to the physical and social infrastructure of local communities, the impacts of shale gas extraction and related development over both the short and long-term could be disproportionate to the economic advantages, which is an unacceptable outcome.

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- ***Land Owners*** – Similarly, private land owners stand to realize a "once in a lifetime" financial gain as dozens of exploration and development interests stake their claim on gas rights throughout the Commonwealth. Property values in prime drilling locations throughout Pennsylvania have escalated dramatically, and have presented these property owners with a window of opportunity for cashing in on planned gas extraction.

Challenges

Many of the activities involved in the development of a Marcellus Shale formation well (e.g. drilling, casing, hydraulic fracturing and well control measures) have evolved over time in the context of technology for vertical well development. The innovation which enables and encourages the development of these so-called "unconventional" shale formation wells, from the oil and gas industry's perspective, is the combination of vertical and horizontal well drilling technology. The development of a horizontal shale formation well through the innovative combination of existing methodologies substantially increases the complexity and scale of the operation, as well as the magnitude of potential adverse effects in the event of an accident or failure. In addition, the presence of the Marcellus Shale formation over such a large portion of Pennsylvania presents the prospect of a very large number of well development sites; it is estimated that as many as 35,000 to 50,000 wells can be drilled into the Marcellus Shale formation by 2030.[9]

Current Oil and Gas Regulatory Format in Pennsylvania

The oil and gas regulatory structure in Pennsylvania was created for vertical well development and is not adequate to manage the escalating development of horizontal shale formation well development throughout our Commonwealth. For example, the existing regulatory structure insufficiently covers activities such as the withdrawal, transport, underground injection, and subsequent management of the high volumes of water required to hydraulically fracture a deep Marcellus Shale formation well. The current regulations are not designed to obtain timely and sufficient information to make well-informed decisions concerning the siting of well pads or to build a database identifying cumulative impacts of well development activities on the scale projected by the oil and gas industry.

The industry has made great strides in leading innovation, but the regulatory framework must address the complexities created by the pressure of time, scale, cost and technology.

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Given the extraordinary opportunities and challenges associated with Marcellus Shale gas extraction, it is incumbent upon key stakeholders to take whatever steps are necessary to ensure the safe and reliable development of this resource in a way that does not repeat the mistakes of the past.

There is no time to lose.

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SCOPE OF THE REPORT

Basis for Recommendations

As stated before, Pennsylvania's existing oil and gas regulatory framework does not anticipate directional drilling and related unconventional well development activities. The sheer magnitude of these innovative practices, in addition to the size of the operations, leads PEC to conclude that unconventional gas development cannot be properly regulated in the current regulatory environment.

The recommendations in this report, if followed, will require substantive change to multiple Pennsylvania regulatory programs, including statutory amendment. Viewed solely from a procedural standpoint– absent the sheer complexity of the issues involved – this slate of proposed recommendations appears daunting. However, Pennsylvania has only limited time to properly manage Marcellus Shale development. As has been learned from past resource extraction, the failure to adopt sufficient and fair protections at the onset will result in significant environmental impacts and long-term costs in the future.

> *Pennsylvania has the opportunity to learn from other states and countries who have recently developed shale reserves, as well as learning from our own past history with natural resources development.*

The single most important part of any regulation or the implementation of the requirements set forth is planning. Pennsylvania has the opportunity to learn from other states and countries that have recently developed shale reserves, as well as learning from our own past history with natural resources development.

The following guiding principles were used by PEC in the formation of the recommendations herein:

- ***Adaptive Management*** – While the recommendations as a whole propose significant changes, we do not believe these changes are the end of the process. The industry will continue to develop; new technologies will be deployed; and the state will have more complete assessments of the effects on environmental and community resources. These progressions will require the cumulative regulatory program applicable to Marcellus Shale extraction to continuously evolve in kind.

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No final rulemaking or statutory enactment should be viewed as a conclusion to the process.

- ***Informed Decision Making*** – This principle is a corollary to adaptive management. Many of the Report's recommendations do not look to new command and control standards; rather, they rely on better informational development and assessment. With a rapidly expanding industry and DEP struggling to keep pace in light of staff and funding constraints, it is essential that the management process ensures that sufficient cumulative, as well as site and activity-specific, considerations are in hand prior to approval of any well operation. Structured correctly, this informational development can also benefit the industry in a number of respects.

- ***Comprehensive Planning and Stakeholder Input*** – Every effort should be made to assess potential cumulative impacts from proposed well development; not only from individual sites but also from a broader perspective. Communities in proximity to well and infrastructure development should be afforded input into the review process to ensure consistency between agency action and local protection efforts. This process should be well understood by all parties, and be fair and timely.

- ***Predictable Process; Incentives for Co-Benefits*** – The regulatory program should be predictable and applied consistently. Incentives should be given to industry members who can advance environmental co-benefits in their well operations.

- ***Best Management Practices*** – It is incumbent on the industry, above and beyond the point of regulation, to employ its own set of best management practices to ensure that extraction, storage and delivery incidents are avoided to the greatest extent possible. If the industry is going to be a long-term presence in our Commonwealth it must act accordingly consistent with recognized principles of sustainable development.

- ***Quick Adoption*** – It is acknowledged that substantial revisions and additions to Pennsylvania's statutory, regulatory and policy structure are required to adequately regulate unconventional shale gas wells. At the same time, it is recognized that the legislative and rulemaking processes will take time. In light of the appetite of the oil and gas industry to put the infrastructure in place to produce and deliver natural gas from the Marcellus Shale formation, it is imperative that all relevant parties put the requisite structure in place as expeditiously as reasonably possible with agreed upon deadlines for progress. All interested parties should work collaboratively to identify standards and practices that will lead to a model

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regulatory program and be willing to follow such standards and practices voluntarily in advance of codification in legislation, regulations and/or agency policy. This will not only expedite the achievement of sound practices but also provide a period of time to "road-test" the practices before formally codified, thereby reducing the possibility of missteps in the formal legislative and regulatory processes

Another fundamental principle to this report, although not delineated in the subsequent recommendations, is proper certification and training. The full life cycle of natural gas well operations, from exploration to delivery, is a complex industrial and technological process. It is essential that the industry ensures that all involved employees and contractors have relevant experience and, as appropriate, professional license or certification.

Structure of the Report

This report begins with broader considerations that should be in place before individual well development activity occurs – namely, how should Pennsylvania account for regional and comprehensive impacts from independent activities.

It then addresses how Pennsylvania should establish sufficient baseline information and assessments prior to approving at-site operations. Included in this discussion are broader siting considerations that should be applied once the DEP is informed of site-specific characteristics.

Once sufficient information is in place to guide the permitting process, the Report identifies existing issues associated with managing the full life cycle of well operations. These issues affect the natural and built environment, and draw upon lessons learned from other industry sectors that are applicable to natural gas extraction and delivery.

The report then incorporates important associated issues with well operations, including the notion of pooling and how the Commonwealth has advanced extraction on state lands.

Finally, this report suggests a framework for implementing the recommendations outlined below.

We have intentionally limited the focus of this report to statutory and regulatory policy issues. As such, we do not address social and public health impacts from Marcellus Shale development. While very important, we felt these issues were not fully discussed at the Conference and are more appropriately addressed in a separate study.

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COMPREHENSIVE PLANNING FOR THE MARCELLUS SHALE

Extraction and delivery of gas from the Marcellus Shale Reserve, and perhaps other shale gas formations that are known to exist in Pennsylvania, will unfold over many decades, so the full extent and impact of this activity is unknown. For this very reason Pennsylvania should approach management in a comprehensive fashion, mindful of potential, long-term cumulative impacts to the natural and built environment.

Our current regulatory process – which authorizes activities on a permit-by-permit basis irrespective of other activity – falls short of this goal. Nor does the current process strive for the proactive identification, development and application of best management practices that promote the Commonwealth's goal of protecting the environment and public health, safety and welfare now and in the future.

As unconventional gas development practices rapidly expand across Pennsylvania, an effective process is needed to assure long-term environmental protection and public welfare. Time is of the essence; the industry will not pause for debate on new program adaptation.

As unconventional gas development practices rapidly expand across Pennsylvania, an effective process is needed to assure long-term environmental protection and public welfare.

As learned at the Conference in May, the success of the industry relies in part on consistency and predictability to support long-term investment and operation plans. What's more, as is discussed in more detail in this report, impacted local governments also depend upon predictability and advance planning in order to effectively implement their own comprehensive plans.

Other states have made noteworthy advances in this regard. For example, Colorado, a state with experience in unconventional gas reserves, went through a concentrated process to formulate a new regulatory framework to provide greater protection through advance planning. This experience is instructive for Pennsylvania.

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In the Spring of 2009, Colorado's newly adopted regulations became effective for all oil and gas operations within their state.[10] Within the regulations Colorado implemented a new well permitting process called a Comprehensive Drilling Plan (CDP). Under this voluntary program, the CDP allows one or more well operators to initiate a comprehensive permit application review process as an alternative to only submitting individual permit applications. Multiple well site operations proposed and/or reasonably foreseeable by the permit applicant(s) in an identified geographic region within a geologic basin are afforded the same comprehensive permit application. The CDP promotes efficient and effective well siting based on cumulative regionally proposed well development.

The Colorado regulations set forth that, when submitting a CDP:

> *"Operators are encouraged to submit the most detailed information practicable about the future activities in the geographic area covered by the Comprehensive Drilling Plan. Detailed information is more likely to lead to identification of specific impacts and agreement regarding measures to minimize adverse impacts."*

The CDP allows for input and comments from the Colorado Division of Wildlife, Division of Public Health and Environment, local government, the Colorado Oil and Gas Commission, and landowners directly impacted by the proposed development in order to address their respective interests; furthering review of cumulative impacts of the industrial development in a given region. As an added incentive, an approved CDP is valid for six (6) years, so additional proposed operations submitted as part of this application may have an expedited permit review process. While the CDP is touted as a benefit to operators for reasons of efficiency and long-term operations planning, the CDP is also a benefit to the State and other interested parties toward better protection of the environment, wildlife, and public health, safety and welfare.

Recommendation

Pennsylvania should adopt an advance planning process similar to Colorado's Comprehensive Drilling Plan to assure implementation of best management practices and community input in natural gas resource development.

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Statutory revisions to the Oil and Gas Act will be required to properly allow DEP the ability to best develop a long-term comprehensive planning and permit process. Examples of necessary changes include allowing approved permits to remain valid for longer than one year, and providing DEP sufficient time to notify and hold a key-stakeholder meeting prior to issuing a plan and subsequent permits.

DEP should develop a planning and pre-permit baseline assessment process (the latter discussed in more detail, below), working with key stakeholders for technical guidance. For example, CDPs could be developed on a regional basis or, as suggested by industry representatives at the Conference, be defined by the characteristics of the natural gas being extracted (which dictates different extraction methods).

While the CDP process should not prevail over site-specific assessment and determination as discussed below, it provides an inclusive and information-driven process to advance well development while accounting for long-term considerations. The CDP process also affords industry a degree of assurance on site feasibility as it develops its own long range capital investment strategy and implements operational planning in particular areas.

The following section addresses site-specific considerations and requirements.

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PRE-PERMITTING AND SITE ASSESSMENT CONSIDERATIONS

Siting Criteria

The surface impacts of Marcellus Shale gas extraction and delivery can be mitigated through better siting of gas wells and their related infrastructure. What is known of the immediate surface impacts from Marcellus Shale gas development is that in order to develop a well, several acres of land must be developed for a drilling pad (which itself likely hosts multiple wells); plus additional acreage for high traffic access roads, gathering systems, compressor and processing stations, water impoundments and other related infrastructure.

Siting of wells and other infrastructure are managed by state statute,[11] implementing regulations,[12] and Technical Guidance Documents[13] which provide suggested best management practices. However, these suggested best management practices are general in nature and in some instances may be waived by DEP. Information gathering in support of permit approval is a weak point in the current permit application process, and does not account for broader regional considerations. As learned at the Conference, Pennsylvania could require more detailed site analyses from the operator regarding the location of proposed development in relation to environmentally sensitive or public resource areas.

Pennsylvania can and should do better. Broader ecological considerations – including habitat fragmentation, proliferation of invasive species, and aquatic uses – should be inherent in the siting process.

The Susquehanna River Basin Commission (SRBC), for example, may require that applicants provide information on the anticipated impact of the proposed project on the recreation, wildlife habitat, the natural environment as well as cultural or archaeological sites, among other regionally important aspects.[14]

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New York's Department of Conservation (DEC) mandates even more information in an Environmental Assessment Form required to accompany each application for a Permit to Drill, Deepen, Plug Back or Convert a Well (the Form sets forth a long list of environmental resources to be identified near the proposed well site.[15]) Additionally, the New York DEC also determined in its 1992 Generic Environmental Impact Statement that "issuance of a drilling permit for a location in a State Parkland, in an Agricultural District, or within 2,000 feet of a municipal water supply well... may be significant and requires a site-specific State Environmental Quality Review determination (environmental impact study)."[16]

Pennsylvania has recently taken steps to recognize that certain environmentally sensitive areas may require greater protective measures. Proposed rulemaking for Title 25 Pa Code Chapter 78 (Section 78.75(a): Area of Alternative Methods) sets forth that:

> *"(a) The Department may designate an area of alternative methods if the Department determines that well drilling requirements beyond those provided in this chapter are necessary to drill, operate or plug a well in a safe and environmentally protective manner."*

On May 17, 2010 the Pennsylvania Environmental Quality Board (EQB) reviewed and approved this proposed rulemaking, and it will now be forwarded to the Attorney General's office for determination before publication in the Pennsylvania Bulletin.[17] While this proposed amendment is a start, it is only small step compared with what other jurisdictions have done.

Pennsylvania can and should do better. Broader ecological considerations – including habitat fragmentation, proliferation of invasive species, and aquatic uses – should be inherent in the siting process.

In addition, special consideration should be given to well operations that occur in proximity to water bodies (natural or man-made) that are utilized for drinking water (e.g. reservoirs and lakes) where even one individual adverse impact can have tremendous, perhaps irreparable, economic and social cost. Concepts used in other regulatory programs such as the Surface Mining Conservation and Reclamation Act,[18] where areas are deemed unsuitable for extraction when in proximity to large scale water supplies, may be appropriate for oil and gas controls. Further, Drinking Water Suppliers should specifically be given notice and opportunity to comment on any proposed permit plan or application within a certain distance of identified storage or source areas.

Again, against the backdrop of large scale drilling, infrastructure and facility development, these considerations are critical to Pennsylvania's long-term environmental health.

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Pre-Drilling Site Assessments

Currently the regulatory structure covering drilling of natural gas wells requires limited site-specific information in the permit application process[19] and an incentive, although not a requirement, to collect baseline water quality information prior to the commencement of drilling.[20] However, the scale, complexity and potential impacts from the drilling and hydraulic fracturing of horizontal natural gas production wells into the Marcellus Shale formation, and potentially other shale formations, warrants a pre-permit application process that accounts for a more in-depth analysis of site specific conditions.

It is well documented that naturally occurring and man-made constituents, as well as the migration of methane, from hydraulic fracturing can affect surface and ground water quality. There are also documented cases of natural gas migration into structures – posing substantial risk of property damage and threat to human safety. The sources and pathways of such constituents can occur naturally or be activity-induced, including old or abandoned wells.

It must be acknowledged that all systems – design, construction and operational – are vulnerable to occasional failure. In addition, the mere act of boring a well is subject to a degree of unavoidable geologic uncertainty. The potential impacts from such failures or unknown conditions can be serious; persist for extended periods of time; and, in some cases, may be irreparable. While both the industry and DEP are making efforts to address these issues, more is needed.

Conceptually, the level of site specific information that should be required prior to the issuance of a permit to develop a natural gas well by means of horizontal drilling and hydraulic fracturing should be based on an "all appropriate inquiry standard." Such a standard has been developed before through negotiated rulemaking as part of the of the federal brownfields redevelopment program.[21] Not all of the specific elements of the federal brownfield "all appropriate inquiry" standard are or should be made applicable to the natural gas well development scenario; however, a number of the elements, if properly adapted, should be incorporated into a site-specific information gathering process.

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Some examples of adaptable elements of the "all appropriate inquiry" standard are as follows:

- ***Reviews of historical sources, such as chain of title documents, aerial photographs, building department records, and land-use records, to determine previous uses and occupancies of the real property within the production unit and adjacent properties*** – Such searches have become routine practice for acquiring interests in real property and, with current electronic database resources, are easily accomplished in a cost effective manner. Further such preliminary inquiries make subsequent inquiries more cost effective.
- ***Reviews of federal, state, and local government environmental records*** – Such a review would disclose the presence of previously permitted extraction activities within the production unit as well as other site conditions brought to the attention of a governmental authority. This information will disclose such relevant information as the presence of contamination from prior activities, the presence and regulatory status of existing registered oil and gas wells, and other potential conditions which may be sources or pathways of exposure for water contaminants or migrating natural gas.
- ***Interviews with past and present owners, operators, and occupants of the real property within the production unit and adjacent properties for the purpose of gathering information about site conditions not found in other records*** – Information from such interviews will disclose the presence of site conditions not recorded in public records or governmental files. Of particular relevance is information relating to unregistered oil and gas wells and other unpermitted or otherwise unknown site conditions which may pose sources and pathways of exposure for water contaminants or migrating natural gas.
- ***Visual inspections of area of the production unit and of adjoining properties*** – A visual inspection of the surface area of the production unit plus an appropriate area adjacent to the perimeter of the production unit by a competent environmental professional will identify surface manifestations of prior activity on the site (*e.g.* well risers, gathering lines, earth disturbances indicating prior excavations).

Currently there are a number of disputed claims by property owners concerning the source of contamination of water supplies, and in some cases the intrusion of natural gas into structures as the result of Marcellus Shale gas well developments. In addition to acquiring relevant information for a more well-informed permit process, the institution of the proposed all appropriate inquiry process will avoid or dramatically reduce disputes

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concerning the source of contamination or natural gas migration by property owners.

The proposed information gathering process also has the potential to provide opportunities for co-benefits throughout the long-term projected life-cycle of shale gas development in Pennsylvania. For example, as noted in the Preface, there are an estimated 184,000 undocumented oil and gas wells throughout the Commonwealth. The presence of unplugged wells provide preferential pathways for the migration of contaminants and natural gas to ground or surface water, and to enclosed structures, and thereby pose potential threats to both the environment and human safety.

In 1992 the Pennsylvania Oil and Gas Act was amended to establish an "orphan well plugging program for wells abandoned before 1985." According to DEP, as of December 2007 about 8,700 abandoned wells have been reported and classified as orphan wells. Over the three year period January 2004 through December 2006, DEP contracted for the plugging of 425 orphan wells at an average plugging cost of approximately $9,650.00 per well.[22]

The pace of locating and plugging orphan wells could be dramatically increased by the systematic collection and recording of the location and status of pre-existing unregistered oil and gas wells through the permit process for new shale formation wells, combined with the establishment of a program to incentivize the permit applicant to decommission and plug the discovered wells as part of the development of the shale gas well. Because the well developer is already mobilized to the site, the average cost of the plugging of orphan wells should be less than the historic average.

The routine collection of other site-specific data over the long-term duration of the shale formation well development process will also provide a meaningful database for assessing the cumulative impacts of future natural gas development in the Commonwealth, thereby enabling the application of adaptive governance of this natural resource extraction activity.

Recommendation

A two-phase permit process should be adopted to drill or alter a well. The first phase is focused on obtaining and documenting site specific information and would culminate in a determination by DEP that the site is appropriate for well development. The second phase would be the final authorization to commence well-drilling activities.

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The specifications of the Phase I permit application process should be developed by DEP with input from stakeholders. To the greatest extent possible, this process should identify other existing models of field data collection that are adaptable to shale formation gas well development. For example, the U. S. Environmental Protection Agency (EPA) recognizes two best practice standards formulated by ASTM International Standards as compliant with the "all appropriate inquiry" standard.[23] Consideration of these ASTM standards and possibly other models is relevant for purposes of formulating the contemplated Phase I data gathering process for Marcellus Shale well development.

Following sufficient field experience and adjustment based on that experience, a determination of what, if any, revisions should be made to the Environmental Quality Board's oil and gas regulations can be made at that time consistent with our adaptive management principle.

The siting of impoundments, particularly in relation to riparian areas and floodplains, is an additional concern. Recent reporting has found numerous occurrences of leakages and spills of treated hydraulic frackwater.[24] In the Dam Safety and Encroachments Act[25] and its implementing regulations,[26] Pennsylvania addresses the siting of impoundments and other ancillary facilities related to well development practices in the vicinity of floodplains. These regulations require a permit to site such features in floodplains.[27] However, given technological advances, such as the ability to site centralized well pads and drill wells thousands of feet in every direction, there is limited justification to permit the siting of any facilities in a floodplain other than perhaps gathering lines and/or pipelines.

Basis for Recommendation

PEC recognizes the importance of an efficient and predictable permit application process. The recommended two-phase approach to natural gas well drilling will require additional information gathering and increase the cost of the permit application process; however, given the nature of the horizontal drilling and hydraulic fracturing, and scale of natural gas production that will be realized for a generation or longer, the recommended information gathering process is a sound measure for all stakeholders.

From the Commonwealth's perspective, the additional information will reduce the occurrence of unintended environmental and community impacts related to contamination of waters and the potential migration of natural gas through otherwise unknown pathways. It will also provide a basis to identify high risk

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areas not suitable for well development, at least without special precautionary measures. DEP already applies this fundamental approach in its mining program, whereby areas may be designated as unsuitable for mining. From the exploration and production industry's perspective, it will establish baseline information that will be available to identify pre-existing conditions not associated with its activities and thereby avoid claims. There also may be the opportunity for realizing co-benefits which are discussed below.

From the industry's perspective, the two-phase process should not decrease the efficiency of the permit process if there is a clear specification of the Phase I information requirements and a reasonable time limit for DEP to review and act on the Phase I application. Furthermore, the first phase information gathering and regulatory approval process should not delay the commencement of well development activities. With proper advance planning and rig scheduling, the completion of the Phase I process could occur well before the scheduled mobilization of equipment to commence the well development process. With the regulatory review and approval of the Phase I permit application completed in advance, the Phase II permit application would serve as the authorization to proceed with well development which should be issued on a relatively short turn-around basis.

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ADDITIONAL PERMITTING PROCESS CONSIDERATIONS

Managing Permit Applications with Limited Time, Staff and Training

The current and anticipated volume of permit applications is overwhelming to current DEP staffing. By the end of 2010, Pennsylvania is expected to employ approximately 193 staff members for permit application review. From January 1st through June 4th of this year, 3,200 permit applications for well drilling (Marcellus and non-Marcellus) were submitted. After an operator files a complete permit application, DEP has only forty five (45) days to review and approve or deny the permit.[28] This overburden has already led to deficient review of permit applications as was raised by the Chesapeake Bay Foundation in successful appeals of three erosion and sedimentation control permits, which were subsequently revoked.[29] If a pre-application baseline assessment were performed and submitted to DEP as proposed above, then a streamlined 45-day process may be appropriate.

In addition to requiring more site-specific information, utilizing a comprehensive planning process (as discussed above) would provide permitting staff with the operator's long-term regional development plans. Long range development plans, in combination with the above specific site assessment recommendations, would allow for efficient and comprehensive permit application review process.

Further concern is caused by the fact that, over the past several years, the difficult economic climate has driven state government to reduce funding to both DEP and DCNR. Though DEP is adding staff to its Oil and Gas Program, it has been expressed that many staff lack sufficient training and expertise with the nature of unconventional gas development. The unfortunate reality is that staff training is typically one of the first items cut when agency funding reductions are put into play.

PEC encourages the General Assembly and Governor to ensure that sufficient funding is available...to ensure that DEP staff are sufficiently trained to implement and enforce the regulatory regime.

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Because Marcellus Shale gas extraction is likely to be the predominant area where new or repositioned staff are utilized in program management, PEC encourages the General Assembly and Governor to ensure that sufficient funding is available – but not merely at the expense of program needs – to ensure that DEP staff are sufficiently trained to implement and enforce the regulatory regime. A sufficiently trained Oil and Gas Program staff also benefits the industry as permits can be more quickly and qualitatively assessed.

Local Government Comment on Proposed Development

The current permitting process does not provide advance notice of proposed well development activities to local governments. During the proposed pre-application baseline assessment and regional cumulative planning period, local governments that will be directly impacted by the proposed development should be provided with information about the proposal and should have a prescribed period within which to comment.

Local governments require long-term planning in order to effectively manage their land use controls and comprehensive plans. Oil and gas well development activities place significant stress on municipal and county infrastructure, especially roads. The current well-by-well permitting process does not provide local governments nor the Commonwealth with any predictability as to future operations, or an assessment of potential impacts.

Providing municipalities with a proposed long-term regional well development plan (akin to the Comprehensive Drilling Plan process discussed above) would allow communities to comment on, and better prepare for, the cumulative anticipated impacts of unconventional well development practices. For example, local governments should be permitted to identify or suggest preferred routes in the community capable of handling the significant truck traffic involved with unconventional gas well development. This effort would also provide regional predictability to the industry.

The proposed process of notifying local government of proposed development and allowing a period for comment is already in place in other regulatory frameworks, such as in the Solid Waste Management Act ("SWMA").[30] Within the SWMA, notices to the municipalities of the application for a waste disposal permit is required to be received by the impacted municipalities 60 days before DEP may issue or deny the permit. This process gives the municipalities a statutorily specified time to submit comments and requires DEP to publish a response to comments as part of the administrative record in the permit application process.

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While some counties in Pennsylvania are becoming proactive in establishing task forces to try to meet the challenges of Marcellus Shale development, communities should not be set at a disadvantage in terms of well development and infrastructure information – a revised permit process should include local governments with sufficient information in advance of operation approval so that they may have effective input in the process and appropriate opportunity to minimize impacts.

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MANAGING THE LIFE CYCLE OF WELL OPERATIONS

Casing and Cementing

New casing and cementing regulations are necessary in order to adapt to the new technology used in unconventional well drilling and development practices in use throughout Pennsylvania today. The techniques used in unconventional well development include underground injection of fracking materials at high pressures; additionally, gas recovered from the target formations tends to be at extremely high pressures. These unconventional conditions vary greatly from traditional well-drilling environments. Pennsylvania has already witnessed individual events of blown or faulty casing leading to gas migration into water wells.[31] DEP has been engaged in proposed rulemaking[32] with new material and design specifications, as well as performance testing, for casing and cementing at well sites. At the time of this report, this proposed rulemaking has been advanced by the Environmental Quality Board (EQB).

Given that...unfortunate events are already occurring, and that better management practices are available and employed by the same companies in other shale gas states, then Pennsylvania should similarly update its casing and cementing requirements.

Recommendation

Until this rulemaking is final PEC believes it is premature to recommend additional measures, but PEC believes the proposed rulemaking as currently written represents a necessary advance in the state's protection program. However, if subsequent contamination or blow-out events prove that even these standards are inadequate, the principle of adaptive management should guide DEP toward an expedited strengthening of the regulatory program.

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Drilling Waste

In all oil and gas well practices during the drilling process, drill cuttings and related fluids produced during drilling may be stored on-site in pits or tanks until drilling is completed. The storage, transportation and disposal of wastes is regulated by the Solid Waste Management Act[33] and related implementing regulations.[34] Once collected, the wastes, now considered residual waste, may be taken off site to a proper disposal site, disposed of on-site in pits,[35] or disposed of through land application techniques.[36] While these practices are no different between traditional and unconventional well development, the volume and constituents of concern in the wastes may differ significantly, including potential higher concentrations of naturally-occurring radioactive material (NORM) in the Marcellus Shale formation.[37] Accordingly, those regulations should be revised to incorporate the new unconventional practices and any resultant constituents of concern.

Recommendation

Pennsylvania's waste handling and storage regulations for drilling activities (included in the Oil and Gas Act and Solid Waste Management Act) should be reviewed in light of the exponential increase in the volume of wastes, including special attention to NORM characteristics and the potential requirement of Waste Management Plans to address capacity concerns. Contaminated and hazardous wastes should be disposed of pursuant to established guidance only at permitted facilities.

Wastewater is more specifically addressed in the following section (Hydraulic Fracturing and Water Management)

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HYDRAULIC FRACTURING AND WATER MANAGEMENT

The extraction of natural gas in the Marcellus Shale requires significant use of another natural resource: water. In fact the sheer volume of water use is what makes Marcellus Shale development "unconventional," and in kind, Pennsylvania's ability to manage water use in relation to this burgeoning industry has proven to be far from adequate. With freshwater use needs averaging two to seven million gallons per well (and with multiple wells per site), the need is great for new authority to establish an effective and complete water management program.

The industry is making significant strides to reduce its demand for freshwater withdrawals for individual well operations. Similarly, it has also reduced its wastewater volumes. Still, the exponential increase in well development across the state has placed tremendous strain on the state's water resources. The need for an effective and complete water program is essential and should be of the highest priority.

With freshwater use needs averaging two to seven million gallons per well...the need for an effective and complete water program is essential and should be of the highest priority.

Withdrawal

DEP does not have full authority to manage water withdrawals from surface and ground water sources. While the state does have reporting requirements for higher volume users, these requirements are used for information purposes only.

The Susquehanna and Delaware River basins are both subject to interstate compacts governing water quantity and quality issues, and the respective Commissions charged with administering those compacts have taken proactive steps toward managing water use in relation to Marcellus Shale development. The SRBC has already developed a comprehensive review and management program for industry withdrawals.[38] At the time of this report, the Delaware River Basin Commission has issued a temporary moratorium on new reviews and approvals until it completes its own program. The Ohio River basin, much of which covers the Marcellus Shale formation, has no corresponding authority to addressing water use and withdrawals.

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While DEP now requires a Water Management Plan in its well development permitting, this plan is prepared pursuant to general guidance, does not require approval, and is of limited utility.

Recommendation

Pennsylvania should grant statutory authority to DEP for water withdrawal management regulations. DEP should develop withdrawal standards for Marcellus Shale development based upon the protocol developed and informational requirements of SRBC.

The SRBC program has proven itself as a model; having been developed in consultation with industry, their program accounts for cumulative impacts and multiple source withdrawals and requires ecological flow analysis with resulting information made openly available to the public. The state should have the ability to limit or prohibit source withdrawals that pose significant adverse impact to personal, commercial or ecological uses.

Water Use

Once water is transferred for treatment and use at a well site, a new set of considerations comes into play. Fracturing (or "frack"), flowback, and produced waters each contain numerous additives and contaminants and, as such, warrant special handling and control.

Flowback and produced waters are stored on-site in pit impoundments or steel tanks. Impoundment incidents (such as seepage, odors, and ignition) have already occurred in Pennsylvania, which does not currently require surface or groundwater monitoring in the vicinity of storage areas.

As mentioned earlier in this Report, another concern is contamination of water supplies from geologic disturbances during the drilling process. A critical information gap exists with respect to this issue – no pre-drilling baseline data exists to identify or confirm contamination events. This information gap is exaggerated by the fact that Pennsylvania does not have standards in place for establishing or operating private water wells. Thus, we do not know if problems exist before gas well development occurs, or what the true nature and extent of any resulting impacts might be. While other regulatory programs require baseline water source assessment prior to activity (e.g. the underground mining program per the Surface Mining Conservation and Reclamation Act[39]), the current oil and gas program lacks this degree of information and assurance.

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Recommendation

Pennsylvania should follow the lead of other shale gas states and require frequent monitoring (both baseline and post-well development) and periodic reporting of surface and groundwater quality in proximity to well sites. Baseline data and monitoring points should guide routine, periodic post-well development data collection.

Further, DEP should ensure that PPC (Preparedness, Prevention and Contingency) Plans for well operations are complete and adequately address ground and surface water contamination issues.

As the protection of private water supply wells is of paramount concern toward protection of public health, safety and welfare, we further believe that Pennsylvania should revisit the idea of developing legislation to manage the construction and maintenance of private water supply wells. Pennsylvania remains one of the few states without private well regulations, and while such efforts have met broad and concerted opposition in the past, the quick expansion of natural gas development may prompt renewed interest in the concept.

Wastewater Disposal

The salinity of wastewater from Marcellus Shale extraction operations can be up to ten times greater than sea water, and up to one-third of the volume of this wastewater can consist of Total Dissolved Solids (TDS).

Even before the development of a single Marcellus Shale well, Pennsylvania's waterways are already significantly impaired. The 2010 Pennsylvania Integrated Water Quality Monitoring and Assessment Report[40] has identified more than 19,000 miles of rivers and streams that do not meet clean water standards and an estimated 5,500 miles are polluted by abandoned mine drainage, which itself can stress assimilative capacity for TDS. There are no inexpensive or immediate solutions to these existing problems, and wastewater from Marcellus Shale operations only compounds the challenge.

Public wastewater facilities do not have the capacity to treat flowback and produced wastewater from Marcellus operations other than through dilution (which does not reduce the mass loading of TDS), nor do public drinking

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water facilities have the capability to treat TDS in their source water. The industry has made significant strides in recycling flowback water and new technology is creating additional avenues for reducing the total volume of high TDS wastewater from natural gas development operations as well as other sources. However, relative to the rapid expansion of Marcellus Shale well development in Pennsylvania, the overall volume of industrial wastewater is significantly increasing.

Again, there appears to be an information gap which is paramount to the Commonwealth's ability to properly regulate. While the industry advises that much of the flowback water is recycled, current estimates are that flowback water only accounts for approximately 20% of all frackwater volume injected into the well. A substantial part of the remaining 80%, known as produced water, returns to the surface over the life of the well. Produced water may have a very high TDS concentration, in addition to concentrations of other sub-surface minerals and NORM. The produced water is not recycled for other fracking operations, but is disposed.

At the time of this report, the DEP is advancing final rulemaking to amend 25 PA Code 95 (Wastewater Treatment Requirements) with new natural gas industry wastewater standards (set at 500 mg/L).[41] West Virginia is currently advancing similar standard revisions to its own program.

Recommendation

The final rulemaking to amend Chapter 95 is a significant and necessary step, and final approval of the proposal in the near term is essential. Though there are very real associated costs, effective abatement or treatment of the increasing volume of flowback wastewater from the Marcellus Shale play is not optional for Pennsylvania or its waterways.

In time, as informational resources increase and better data is obtained concerning assimilative capacity of individual waterways, this standard may be revisited and equal standards applied to all industrial and commercial sectors. Additionally, subsequent rulemaking should look for ways to incentivize the development and use of alternative water treatment technologies.

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Compliance, Monitoring and Enforcement

Leakage of frack and flowback water has already occurred in multiple instances across Pennsylvania from occurrences such as human error, equipment malfunction, poor siting of equipment, and other operational causes that cannot be prevented through regulation alone. Consistency of monitoring by the state and industry, along with proper certification of all operators on site, is essential to minimizing these inherent risks.

Recommendation

Credible inspection and enforcement programs must be implemented by DEP. In addition, the industry should formally develop and adopt best management practices for day-to-day operations, including the activities of subcontractors. These operations should be performed by properly certified personnel, as appropriate.

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POST-WELL DEVELOPMENT MONITORING AND DATA COLLECTION

The development of the Marcellus Shale formation through horizontal drilling and hydraulic fracturing in Pennsylvania dates back to 2003. However, based on well permits issued, Marcellus well development activity did not start in earnest until late 2008 and 2009. According to DEP statistics, 476 permits for Marcellus Shale wells were issued in 2008 and 1,984 permits were issued in 2009. Recent projections estimate that the number of Marcellus Shale wells drilled will increase annually from approximately 1,600 wells in 2010 to approximately 3,500 wells in 2020.[42]

Based on published information related to unconventional shale gas well development that has been occurring for longer periods of time, (i.e, the Barnett Shale gas play in metropolitan Fort Worth, Texas which commenced in 1999), there is a concern that the cumulative impact of large-scale shale gas development in Pennsylvania will cause environmental and human health impacts. However, at this point in the trajectory of shale gas development there is an insufficient amount of empirical data to determine the nature and degree of severity of such potential cumulative impacts.

The development of a regulatory structure to protect human health and the environment over the course of shale gas development in the Commonwealth is imperative and should be based on the principle of adaptive management; but this principle requires affirmative efforts to develop sound, publicly accessible databases of empirical evidence. The resulting data should drive future regulatory review and amendment; including the consideration of potential collective operations emission standards for air permitting.

> *The development of a regulatory structure to protect human health and the environment over the course of shale gas development in the Commonwealth is imperative and should be based on the principle of adaptive management.*

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Recommendation

DEP should also develop a regulatory standard for long-term routine ambient air quality monitoring recordkeeping and reporting to assess the need for air emission controls for emissions from point sources and fugitive sources at unconventional shale gas pads and other air emission sources (e.g. compressor stations, flowback impoundments) associated with the production and delivery of natural gas.

DEP is currently deploying pilot Air Emission Monitoring Networks throughout the state. PEC supports this effort and encourages the Department to not only consider emissions in relation to prevailing emission standards, but also in light of potential public health impacts resulting from prolonged exposure or cumulative emissions.

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FINANCIAL ASSURANCE

The current statutory mechanism for providing financial assurance for the decommissioning of oil and gas wells is obsolete and inadequate to cover well decommissioning, site reclamation and potential post reclamation responsibilities, particularly wells developed in the Marcellus Shale formation.

Section 215 of the Oil and Gas Act specifies that the owner or operator of an oil or gas well shall file a bond with the DEP in the amount of $2,500 per well or a blanket bond in the amount of $25,000 for all wells in Pennsylvania enumerated in the bond to assure the availability of funds to cover the cost of compliance with the drilling, water supply replacement, restoration and plugging requirements in the act. Section 215 also authorizes the Environmental Quality Board (EQB) to adjust the bond amount specifications to reflect the cost to the Commonwealth to perform well plugging. Section 303 of the Oil and Gas Regulations[43] currently specifies the statutorily prescribed amounts.

At the Conference, DEP Secretary John Hanger identified these bonding specifications as one of the areas of the existing oil and gas regulatory structure that must be strengthened to assure the proper decommissioning and reclamation of Marcellus Shale formation wells and ancillary facilities. PEC concurs with that assessment.

The revision of the existing bond structure may be accomplished either through EQB rule-making or through legislation. There are no proposed amendments pending before the EQB to revise the bonding provisions in Chapter 78 of the Pennsylvania Code. At least one bill has been introduced to the Pennsylvania House of Representatives to amend a number of the provisions of the Oil and Gas Act, including the bonding specifications of Section 215.[44]

A trust-based mechanism should be more adaptable than bonds over the life cycle of a Marcellus Shale well development and take advantage of economies of scale for the major developers of Marcellus Shale production units.

PEC believes that it is important to offer a financial assurance mechanism that is more adaptive than the traditional bond instruments prescribed in Section 215 of the Oil and Gas Act. Additionally, there should be an increase in the dollar amount of financial assurance available to the Commonwealth if a well owner/operator defaults on its regulatory obligation to decommission wells and ancillary facilities, reclaim the site and perform any post reclamation activities that might be required. PEC further believes that the

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alternative financial assurance mechanism established by DEP in the surface mining program is a model which could be adapted to the oil and gas program.

This alternative financial assurance mechanism is based on the establishment of a trust fund. A surface mine permittee wishing to avail itself of the alternative financial assurance program has the option of establishing a stand-alone trust with a third-party trustee or participate in a Master Trust established by the Clean Streams Foundation. The trust is funded in accordance with tailored specifications set forth in a consent order and an agreement between DEP and the permitee or other responsible party. This program is described on the DEP website.[45]

DEP has accumulated considerable experience with the application of an innovative alternative financial assurance mechanism in the surface mining program. Building on that experience, PEC believes that a trust-based alternative to bonding can be adapted from the surface mining program.

A trust-based mechanism should be more adaptable than bonds over the life cycle of a Marcellus Shale well development and take advantage of economies of scale for the major developers of Marcellus Shale production units. The prospect of having trust assets returned to the well developer should also create the incentive to perform the requisite decommissioning and reclamation activities promptly and more completely so as to reduce the potential for post reclamation activities.

Among the key questions to be considered in the establishment of a trust structure are:

- Should the trust fund cover responsibilities in addition to plugging and reclamation (*e.g.*, operation and maintenance of post construction erosion and sediment BMPs; water replacement responsibilities, if any; required routine monitoring, if any)?
- Utilization of a Centralized Master Trust (such as the Clean Streams Foundation) vs. Commercial Trustees
- Transfers of ownership/responsibility over the life-cycle of the well
- Principles for determining the trust balance for major players
- Formula for funding
- Criteria for draw-down or reduction in fund by developer
- Administrative fees

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Recommendation

PEC recommends that a stakeholders group be convened to create the structure of a trust-based alternative to the bonding system currently prescribed by the Oil and Gas Act.

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OTHER CONSIDERATIONS

Pooling and Midstream Operations

Pooling is a term used in the oil and gas industry to define the consolidation of neighboring units of mineral rights into large unitized tracts of developable mineral pools. Pooling can also be a term used to address the consolidation and sharing of ancillary well development, gathering, production, and gas processing infrastructure for the purpose of reducing surface impacts of well development, production and delivery. Pennsylvania's current regulatory framework does not address pooling in regards to Marcellus Shale or other unconventional gas reserves, and does not address pooling of infrastructure.

Pooling of mineral rights can benefit operators via cost savings, such as consolidation of well pads and related well development infrastructure. Thus the pooling of mineral rights, if adopted in Pennsylvania, should reduce surface impacts. Consolidation and pooling of well development, production and delivery infrastructure should likewise reduce surface impacts.

Pooling of well development infrastructure would reduce surface impacts, benefit industry via cost savings (as learned from industry representatives at the Conference), and would allow the Commonwealth to appropriately address anticipated impacts...

There is precedent authority under the Pennsylvania Oil and Gas Conservation Law[46] to address pooling of mineral rights. However, this law only applies to extraction activities at depths below the Onondaga horizon – as Marcellus Shale and other unconventional shale plays are above the Onondaga horizon, the Oil and Gas Conservation Law is not applicable.

Beyond the Oil and Gas Conservation Law, there is no program in Pennsylvania for unitization, pooling, or spacing of unconventional wells in order to prohibit waste, create a pool to incorporate implicated reserves, or space wells in a manner that would promote efficiency, reduce surface impacts, and protect correlative rights.

There are many examples of other state pooling regulations which Pennsylvania might consider regarding the pooling of mineral rights; especially as to the functioning of the commission or agency which hears pooling requests, the parties which are able to request pooling, the risks or

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penalties as to non-consenting parties to the pooling order, and as to the incentives in place to promote voluntary pooling.

There are also examples from other states which support and promote the pooling of infrastructure to reduce surface impacts. Colorado's laws address pooling by stating that "[t]he commingling of production from multiple formations or wells is encouraged in order to maximize the efficient use of wellbores and to minimize the surface disturbance from oil and gas operations."[47] Colorado's rules further provide that "[w]here practicable, operators shall consolidate facilities and pipeline rights-of-way in order to minimize adverse impacts to wildlife resources, including fragmentation of wildlife habitat, as well as cumulative impacts."[48]

As is discussed throughout this report, region-wide comprehensive planning and pre-permitting baseline site assessments as to siting of well development activities and related facilities will allow for an assessment of the cumulative long term impacts of unconventional shale gas plays. Consolidation and/or pooling of infrastructure should be incorporated into this suggested approach. Pooling of well development infrastructure would reduce surface impacts, benefit industry via cost savings (as learned from industry representatives at the Conference), and would allow the Commonwealth to appropriately address anticipated impacts of same.

Recommendation

PEC recommends that Pennsylvania adopt new legislation and/or update existing legislation to include Marcellus Shale and other similar unconventional gas plays within pooling laws, provided that measures are also adopted to incentivize and require the consolidation of surface infrastructure from multiple wells (and indeed multiple operators).

If the industry receives the benefit of pooling options for mineral rights, it should equally be required to minimize surface impacts. Colorado provides examples through its rules[49] that gathering lines and other facilities be consolidated and shared by operators to reduce surface and cumulative impacts. Pennsylvania should involve key stakeholders in this discussion in order to provide appropriate technical guidance. This may be an issue for the Pennsylvania PUC to address, pending the outcome of their hearings on determining jurisdiction over mid-stream facilities including gathering lines.

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Marcellus Shale Development on State Land

The issue of leasing state-owned land for Marcellus Shale development has been controversial, primarily for two reasons: (1) the leasing has been driven by the need for general revenue at a time of continuing state budget deficits; and (2) the leasing has been done primarily on state forest lands. In fact, the state has been diverting revenue from the Oil & Gas Lease Fund to help balance the state budget.

The Pennsylvania Department of Conservation and Natural Resources (DCNR) has leased 137,896 acres of state forest land over the past two years for Marcellus Shale development. This leasing has been performed pursuant to directives from the Governor and General Assembly to reach prescribed annual revenue targets. While DCNR has made efforts with limited time and resources to ensure that leasing does not adversely impact critical resource and recreational uses, it remains to be seen what the full significance of this development will be for the state's public land.

Legislation has been introduced in the General Assembly that would place a temporary moratorium on any additional state forest land leasing until a complete environmental and community impact study can be performed by DCNR. Many organizations – including PEC – have been supportive of this proposal. Other legislation has been introduced that would direct future leasing to other state lands which do not pose quite the resource-sensitivity concerns that state forest lands do.

These different considerations are instructive for an additional reason: unlike the state forest system, the state owns only a minority of the mineral estates underlying state park lands. As such, DCNR has limited legal authority to manage the pace or extent of development of Marcellus Shale under those lands.

Recommendations

- **Pennsylvania's state forest and park systems represent a century of public *and* private investment in protecting natural resources and ensuring public access. Decisions affecting these lands should not be driven solely by the need for revenue.**

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Recommendations *(continued)*

- **The Commonwealth should impose a temporary moratorium on the leasing of *additional* state forest land (i.e. the moratorium should not affect existing, valid leases) until a comprehensive environmental and community impact assessment can be completed. Sufficient time must be afforded for performance of this assessment so that impacts can be fully realized and understood. This assessment should guide the extent of future development, if any, on state forest land.**
- **The Commonwealth should proactively work with the natural gas industry and mineral rights owners to address concerns relating to natural gas extraction under state park lands. Factoring in site-specific considerations, the state and industry should design and implement best management practices to avoid unnecessary or adverse impacts to state park lands.**

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ADVANCING PENNSYLVANIA'S PROGRAM: RECOMMENDED NEXT STEPS

While DEP has been making significant strides to catch up to the unconventional shale gas industry's practices, they are limited in their authority and the rulemaking processes can be time consuming. Additionally, the General Assembly requires a lengthy process before it can pass legislation addressing the new unconventional shale gas practices and providing DEP with additional and appropriate authority. Moreover, the participation of the industry, local governments, environmental interests, and other involved stakeholders is both inefficient as well as ancillary to the current process.

Pennsylvania should look to quickly adapt its oil and gas management program to better account for the scale of unconventional operations, and unique issues inherent in the Marcellus Shale formation.

To date DEP has no option but to advance rulemaking in piecemeal fashion, rather than developing a comprehensive change to the entire framework. All the while, they are issuing new permits for drilling.

Recommendation

PEC recommends that a stakeholder process be established to develop language-ready statutory and rulemaking packages that update and expand Pennsylvania's environmental management framework. The issues and recommendations presented in this report should be a core focus. This process should be advanced quickly given growing concerns relating to current and future issues cited with the standing management regime. The General Assembly and Administration should commit to prompt consideration and action on the resulting product of the process.

While it would require a somewhat novel and expedited approach to rulemaking, Pennsylvania should look to quickly adapt its oil and gas management program to better account for the scale of unconventional operations, and unique issues inherent in the Marcellus Shale formation. Other states with shale gas reserves have demonstrated that comprehensive revision to an environmental management program is, in fact, possible.[50]

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The piecemeal fashion of current regulatory development has proven slow despite the rapid expansion of the industry, and insufficient in relation to comprehensive and regional concerns. The unconventional nature of Marcellus Shale requires an unconventional approach, but one that is comprehensive, careful and inclusive to accomplish best outcomes for all Pennsylvanians.

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CONCLUSION

The purpose of the Pennsylvania Marcellus Shale Policy Conference was to identify and interpret the best practices in the development of deep shale resources. Through this, stakeholders throughout Pennsylvania would have available to them guidelines for statutory and regulatory measures that, if enacted, would help ensure that the Commonwealth had learned all that it could from industry, government, the affected communities, municipalities, as well as other states that have come before us in the management of this industry.

The findings of this report are just such an interpretation. They reflect the thoughtful and detailed consideration of the input provided from the principals, decision-makers and industry experts who shared their experience and perspectives on the Pennsylvania Marcellus Shale. As such, the Pennsylvania Environmental Council respectfully submits that these findings and recommendations represent a framework for action that cannot and should not be overlooked.

Throughout Pennsylvania's history, our natural resources have been exploited for industrial purposes without the benefit of careful consideration and forethought. The price paid in exchange for this rapaciousness can never be fully calculated, yet remains evident in the forests, waterways, and communities and that cost has been shouldered by generations that followed the development.

> *Throughout Pennsylvania's history, our natural resources have been exploited for industrial purposes without the benefit of careful consideration and forethought. More recently, accidents at drilling rigs...highlight the need for prompt and effective reform.*

More recently, accidents at drilling rigs have captured the attention of the news media, regulators and Pennsylvania citizens. These incidents cannot and should not be ignored – they highlight the need for prompt and effective reform.

At the time of this report, the spot market for natural gas is considered to be temporarily undervalued, with gas prices approaching $4.50 per thousand cubic feet. Even at that low price, the Marcellus Shale represents a natural resource whose development can be valued at $1-2 billion (in 2010 dollars) in Pennsylvania. Considered in this context, PEC urges that a long-term view of development be adopted which allows all stakeholders to realize the benefits of the resource while safeguarding the health and safety of our citizens and

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the environment that has still not yet fully recovered from past resource development movements.

Pennsylvania has an extraordinary opportunity to enact the nation's best body of laws governing the extraction of a vast natural resource. Such action would effectively legislate the nation's best practices and make them the standard by which the Marcellus Shale is developed and provides the benefits to the Commonwealth that have been heralded as the promise of this new industry.

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[44] House Bill 2213 (P.N. 3821) of the 2009-2010 Session proposes, among other things, to raise the minimum bonding amounts from $2,500 to $12,000 for single conventional wells and to $150,000 for Marcellus Shale wells utilizing hydraulic fracturing and from $25,000 to $240,000 for multiple wells identified in a blanket bond. Marcellus Shale wells would be ineligible for blanket bonds.

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The Marcellus Shale Amendments

A Proposal for Reforming the Pennsylvania Oil & Gas Act

Pennsylvania Environmental Council
Chesapeake Bay Foundation

May 2011

Introduction

In 2010 the Pennsylvania Environmental Council (PEC) released a report – *Developing the Marcellus Shale* – outlining policy recommendations for improving Pennsylvania's oversight and management of unconventional shale gas development. PEC's policy recommendations were based on the following principles to guide adoption and implementation:

- Adaptive Management
- Informed Decision Making
- Comprehensive Planning and Stakeholder Input
- Predictable Processes and Incentives for Co-benefits
- Use of Best Management Practices

Since the release of the report, the Pennsylvania Department of Environmental Protection (DEP) has made extraordinary efforts to advance meaningful changes to regulatory provisions governing shale gas extraction; most notably the adoption of stringent standards applicable to casing and cementing of wells, as well as wastewater disposal restrictions. However, as incidents continue to occur throughout the Commonwealth, it is clear that additional authority and changes are necessary – and the need is immediate.

PEC, in partnership with the Chesapeake Bay Foundation, is releasing this proposal for amending the Pennsylvania Oil & Gas Act. These recommendations were developed following discussions with the Pennsylvania Chapter of The Nature Conservancy, representatives of industry, community interests, legislators, and state regulatory agencies.

Proposed Oil & Gas Act Amendment Objectives

The proposed statutory amendments have two primary objectives to increase public confidence in the ability of Pennsylvania to "get it right" in regulating natural gas shale development, and in the industry to comply with environmental safeguards.

- Reform the permit process to facilitate greater stakeholder input and site analysis.
- Set clear and appropriate protection standards in light of the hydraulic fracturing process and the degree of infrastructure required for shale gas extraction.

To the first objective, PEC is proposing that the permitting process be expanded into a two-phase process that requires enhanced collection and review of site-specific data prior to authorization of well activities. In our view the current process – reliant on a very tight approval timeframe – is inappropriate given the nature and location of unconventional shale gas development wells.

This same reason leads to the second objective of setting more restrictive conditions in the Oil & Gas Act. Pennsylvania has already experienced several incidents which display the significant potential for adverse impacts to public and natural resources, whether from failures of technology, adequate control, or human error. Therefore it is necessary to set greater controls in the law itself, and require the deployment of best management practices for any variance to ensure sufficient protections are in place.

Special Notes

Regional Comprehensive Planning

An additional goal of our efforts is the promotion of regional comprehensive planning to preemptively avoid adverse impacts to sensitive public and natural resources, allow for the consolidation of well site related infrastructure, and reduce the potential for cumulative impacts. After careful deliberation, we believe that it may be necessary to develop the framework for regional planning outside the parameters of the Oil & Gas Act. The Addendum to this proposal includes a series of ideas for enhancing local planning and decision making, both for well sites as well as associated infrastructure. Additionally, we reference the voluntary planning method adopted for shale gas activities in Colorado.

Public Health

As with PEC's report from last year, the proposed amendments do not directly address concerns relating to public health. These issues continue to be of vital and immediate importance in the broader Marcellus Shale debate. However, we believe this issue is best addressed by qualified health experts through appropriate study. We urge the state to aggressively support this work.

Structure of the Proposal

The proposed amendments to the Oil & Gas Act are separated into three parts:

Part One:	Proposed changes to Section 103 (Definitions).
Part Two:	Proposed changes to Section 201 (Permitting Process)
Part Three:	Additional proposed changes to all Chapters of the Oil & Gas Act for environmental and public protection.

In addition, we have included an Addendum which identifies potential opportunities to enhance regional planning and participation beyond the framework of the Oil & Gas Act.

Unless otherwise noted, we recommend that all amendments – including the enhanced permitting framework in Part Two – become effective no more than 12 months after the date of statutory enactment.

Part One: Proposed Changes to Oil & Gas Act Definitions

Section 103 of the Oil & Gas Act should be amended pursuant to the following recommendations. These amendments are necessary for consistency and to implement other recommendations in this proposal. Suggested statutory language is noted in *italicized font*; otherwise the descriptions provided are guidance for new or amended language.

- Amend the definition of Alteration by removing exception (2). This exception is inconsistent with the overall definition and not appropriate in light of unconventional shale gas development.
- Add a new definition for Ancillary Facilities. At a minimum, this definition should include well site access roads, pipelines to and from the well site, and water (fresh, recycled, flowback or produced) impoundment or holding tanks used or located on the well site.
- Add a definition for Best Management Practices. Best Management Practices should be defined as standards established by DEP through technical guidance. These standards should identify industry practices and actions that can be utilized to better protect natural resources, communities, and human health. The technical guidance should be reviewed and updated (as appropriate) at least every three years.
- Add a definition for Body of Water. The definition should include streams, as well as natural or artificial lakes, ponds, reservoirs, swamps, marshes or wetlands.
- Amend the definition of Department to read: *The Department of Environmental Protection of the Commonwealth.*
- Add the following definition of Flood: *A general but temporary condition of partial or complete inundation of normally dry land areas from the overflow of streams, rivers or other waters of this Commonwealth.*
- Add the following definition of Floodplain: *The Lands adjoining a river or stream that have been or may be expected to be inundated by flood waters in a 100-year frequency flood. Unless otherwise specified, the boundary of the Floodplain is as indicated on maps and flood insurance studies provided by the Federal Emergency Management Agency or equivalent Floodplain maps and studies. In an area where no such maps or studies have defined the boundary of the 100-year Floodplain, it is assumed, absent evidence to the contrary, that the Floodplain extends from the Stream to 100 feet from the top of the streambank.*
- Add the following definition of High Volume Hydraulic Fracturing: *Natural gas wells that use or are expected to use greater than 80,000 gallons or equivalent of hydraulic fracturing fluids, including water.*

- Add the following definition of Hydraulic Fracturing: *A well stimulation technique which consists of pumping water, chemicals and a propping agent, such as sand, or other fluids and materials down the wellbore under high pressure to create and maintain induced fractures in the hydrocarbon-bearing rock of the target geologic formation.*
- Add the following definition of Hydraulic Fracturing Fluid(s): *A mixture of water, chemicals and propping agents or other fluids and materials used in the hydraulic fracturing process.*
- Add the following definition of Post Construction Stormwater Management: *A site-specific plan identifying Best Management Practices to manage changes in stormwater runoff volume, rate and water quality after earth disturbance activities have ended and the project site is permanently stabilized.*
- Add the following definition of Secretary: *The Secretary of Environmental Protection of the Commonwealth.*
- Add the following definition of Stream: *A Watercourse.*
- Add the following definition of Surface: *The uppermost portion of the Earth's crust, including land and aquatic features.*
- Add the following definition of Surface Owner: *A person who holds legal or equitable title to the surface of a parcel of real property.* This definition should be used consistently throughout the Act.
- Add the following definition of Unconventional Well: *A Well that requires the utilization of High Volume Hydraulic Fracturing.*
- Add the following definition of Water Purveyor: *The owner or operator of a public water supply.*
- Add the following definition of Water Supply: *A supply of water for human consumption or use, or for agricultural, commercial, industrial or other legitimate beneficial use.*
- Add the following definition of Watercourse: *A channel or conveyance of surface water having defined bed and banks, whether natural or artificial, with perennial or intermittent flow.*
- Add the following definition of Well Site: *The area occupied by the equipment or facilities necessary for, or incidental to, the drilling, production, servicing, or plugging of a well.*

Part Two: Restructuring the Framework of the Oil and Gas Act Permitting Process

Unconventional shale gas extraction is a highly industrialized process; requiring a significant amount of equipment, infrastructure and ancillary activity, including the management of large volumes of hydraulic fracturing and waste fluids. This industrial scale process occurs out in the open, often in close proximity to people and sensitive natural resources.

The existing permit procedure established by Chapter Two of the Oil & Gas Act was not written in contemplation of unconventional shale gas development. It does not provide sufficient information gathering and analysis requirements about site suitability, existing conditions on the proposed site, or potential regional considerations. It also does not allow DEP sufficient time to properly review permit applications, nor allow local interests sufficient opportunity to contribute information to the review process.

To address these shortfalls the Oil & Gas Act should be amended to reform well permitting into a two stage process, consistent with the framework outlined below. Please reference Part One for definition reference; additional amendments to Section 103 may be required to fully effect this proposal.

1. Add a new section to the Oil and Gas Act ("Section 201A") establishing a new permit process for Unconventional Wells.
    a. The existing Section 201 (amended with conforming language) would remain in place and continue to govern the permit process for natural gas wells developed without High Volume Hydraulic Fracturing.
2. Section 201A would require a two-phase permit process for Unconventional Wells.
    a. The "Phase I Permit Application Process" will provide approval of the location of a proposed Well Site. The Phase I application process can be waived if the proposed Well Site is included in an area-wide comprehensive plan approved by DEP (*see*, 7. below)
    b. The "Phase II Permit Application Process", described in greater detail below, will be used to provide authorization to develop a well at an approved location.
3. The "Phase I Permit Application Process" will include a site assessment requiring the following elements:
    a. Preparation of a "Notice of Intent" to submit a Phase I application which shall be submitted by certified mail, return receipt requested, to the county; the local municipality; all Surface Owners within 2,500 feet of the proposed Well Site, and any facilities or improvements ancillary to the development or servicing of the Well Site, including equipment, buildings, tanks, impoundments, and non-public access roads; and any Water Purveyor drawing source water from a surface water or ground water unit within the above-described area. DEP shall notify the Pennsylvania Fish & Boat Commission, Pennsylvania Game Commission, and the appropriate County Conservation District of the "Notice of Intent".
        i. The notice of intent shall include a copy of the Phase I Permit Application Form and/or checklist of the information required to complete the application form (*see* 3.b. below) and offer the opportunity to any recipient who may have information relevant to the completion of the form (*e.g.* current or prior site uses, pre-existing

site conditions, or other limiting factors) to provide such information to the applicant within 20 days of receipt of the notice.

ii. In the event the applicant receives potentially relevant information from a recipient of the Notice of Intent, or any other source, it shall incorporate such information into the Phase I application unless the applicant can demonstrate that it is not credible.

iii. If the information received indicates the need for follow up investigation by the applicant, the applicant shall undertake such follow-up investigations as may be reasonably necessary.

b. Phase I Application Form should include:

i. Identification of applicant and proposed Well Site.

ii. Identification and contact information for all parties receiving the Notice of Intent

iii. Categorization of the proposed Well Site as a "high population density area" (see, *e.g.* Section 603. b. of the Colorado Oil and Gas Code; http://cogcc.state.co.us/), forest land, wildlife habitat, public recreation land, agricultural land, or industrial land, or other.

iv. Specification of requisite site assessment information based on Site Assessment Checklist (*see* 3.c.)

v. An alternative analysis for Well siting which demonstrates that options to avoid or minimize surface disturbance, forest fragmentation and other impacts on natural resources where identified and evaluated and, in cases where such options are not selected, to explain why other well locations are proposed. The analysis should include the extent to which pre-existing permanent infrastructure may be used in lieu of construction of additional infrastructure. This requirement can be waived if the operator performs or participates in a county or regional comprehensive plan.

c. Site Assessment Checklist developed by DEP, in a Technical Guidance document. The checklist should include, without limitation:

i. The identification, on a scaled drawing, of all existing improvements or uses within 2,500 feet of the proposed Well Site and any Ancillary Facilities.

ii. Topographic surface contour information.

iii. Information available from existing data bases, county records, local municipality records and/or Surface Owners concerning prior surface and subsurface uses or other potentially limiting conditions within the proposed Well Site.

iv. Identification of designated post-well development surface use(s).

- v. Information concerning the location, protection status/designated use and baseline water quality of Streams, Watercourses, Bodies of Water, and private or public water supply sources within 2,500 of the Well Site.
- vi. Pennsylvania Natural Diversity Index (PNDI), County Natural Heritage Inventories, and other ecological baseline information including, but not limited to high conservation value forest areas.
- vii. The location of pre-existing, permanent infrastructure (*e.g.* gathering lines, compressor stations, metering and processing facilities) within 2,500 feet of the proposed Well Site.
- viii. Tentative locations of the well pad and ancillary facilities and improvements.
- ix. A tentative description of the facilities and improvements to be constructed as part of the well development.
- x. A description of applicant-proposed best management practices.

4. Phase I Application Review and Approval Process

   a. Submittal to DEP with prescribed application fee.

   b. Determination of administrative completeness by DEP.

   c. Publication of application in Pennsylvania Bulletin and notice of 30 day comment period.

   d. Applicant submits notice of comment period by certified mail, return receipt requested, to the recipients of Notice of Intent (this notice is waived if the applicant obtains and submits to DEP written acknowledgements from all recipients of the Notice of Intent that they have participated in the preparation of, or reviewed the Phase I Application, and have no further comment).

   e. In certain specified circumstances, DEP may request additional information from the applicant if necessary to evaluate the application or comments received concerning the application.

   f. DEP is obligated to take action on Phase I Applications within 90 days of the close of the public comment period or 45 days after the applicant has fully complied with any request by DEP for additional information, whichever is later.

   g. DEP's approval may include site-specific determinations, including variances from or additions to setback distances established in Section 205 of the Act; as well as requiring implementation of best management practices.

   h. Through regulation, DEP may establish standards for withholding permit approval.

5. Phase I Approvals
    a. Effective for 3 years.
    b. Transferable to another qualified applicant with notice and pre-approval of DEP.
6. Phase II Well Development Permit
    a. Modeled after current permit process as modified to account for the Phase I process.
7. Evaluate Alternatives for an Area-wide Comprehensive Plan Process
    a. *See* Section 216 of the Colorado Oil and Gas Code (http://cogcc.state.co.us/)

Part Three: Other Proposed Amendments to the Oil & Gas Act

Please note that the following recommendations are interlinked with the amendments in Part One and Part Two of this proposal.

1. Add a statement in Section 201 that Well Operators have an affirmative obligation to avoid or minimize impacts to natural resources and public health.

2. To ensure sufficient statutory authority, add a provision to Section 201 that DEP shall have the authority pursuant to the Clean Streams Law (P.L. 1987, No. 394) to regulate water withdrawal for use with any Unconventional Well and to protect the ecological health of water resources.

3. To better protect Surface structures and private water supplies, amend Section 205(a) to:
    - Increase the Well Site setback standard to 500 feet for Unconventional Wells.
    - Require implementation of Best Management Practices as a condition of any waiver to the setback standard.

    Note: Please also see 8, below, for additional recommendations to protect private water supplies.

4. To better protect water resources, amend Section 205(b) as follows:
    - Remove reliance on USGS Topographic Maps for water resource identification. Instead, apply setback standards to any Watercourse, Body of Water, or Wetland.
    - Increase the setback standard to 300 feet for Unconventional Wells.
    - For designated High Quality or Exceptional Value Waters, increase the setback standard to 500 feet.
    - Require implementation of Best Management Practices as a condition of any waiver to the setback standards.
    - If a Well Site is located within a Floodplain, prohibit the use of impoundment pits for recycled, produced or flowback waters resulting from, or for use with, an Unconventional Well.

- Provide DEP with additional authority to establish further protective measures for the storage of hazardous chemicals or materials on the Well Site that is within a Floodplain or 500 feet of a Watercourse, Body of Water, or Wetland.

5. To better protect sensitive public and natural resources, amend Section 205(c) as follows:
    - Add the following as listed resources:
        - Sources used for public drinking water supplies
        - Whether the proposed Well Site location is within a Floodplain
        - Wild and Wilderness Trout Streams
        - High Quality or Exceptional Value Waters
        - Exceptional Value Wetlands
    - Expressly allow DEP to condition or deny a permit application based upon potential impacts to the resources listed in Section 205(c).
    - Require DEP to consult with County Conservation Districts regarding potential impacts to any resources listed in Section 205(c).
    - Require DEP to consult with the Pennsylvania Fish & Boat Commission when there are potential impacts to Wild and Wilderness Trout Streams, High Quality or Exceptional Value Waters, or Exceptional Value Wetlands.

6. To better address stormwater impacts associated with Well Sites and Ancillary Facilities, amend Section 206 as follows:
    - In Section 206(b): Require that, upon temporary or permanent cessation of all earth moving activities at a Well Site, stabilization must occur in a manner consistent with Title 25, Chapter 105 of the Pennsylvania Code.
    - In Section 206(c): Require the completion of a Post-Construction Stormwater Management Plan within nine months of completion of a Well.
    - Expand Section 206(d) to include reclamation or remediation of a Well Site.

7. To better address concerns relating to Well Site impoundment pits, amend Section 208 as follows:
    - Require DEP to perform a sufficiency analysis on proposed containment systems for the storage of recycled, produced or flowback waters on the Well Site.
    - For any surface impoundments used to temporarily store recycled, flowback or produced water, require the use of a dual liner system with leak detection monitoring systems. Require DEP to inspect any such impoundments on, at a minimum, a monthly basis.

8. For additional protections for private water supplies, amend Section 208 as follows:
    - Mandate pre-drilling private water supply baseline surveys within 2,500 feet from the Well Site.
    - Amend Section 208(a) to require that restored or replaced water supplies meet applicable water quality standards consistent with the Federal and State Safe Drinking Water Acts.
    - Amend Section 208(c) and (d) to expand the presumption of liability to 2,500 feet from the Well Site, for a period of 12 months.

9. To enhance public disclosure and better identify potential impacts to Surface Owners and the environment, amend Well reporting requirements in the Oil & Gas Act to include the following:

- Operators must file a Well Stimulation Record with DEP, including (but not limited to) the following sets of information:
    - Pump rate, pressure and total volume used for Hydraulic Fracturing.
    - List of all hazardous chemicals used for Hydraulic Fracturing.
    - Identification of all water sources used for Hydraulic Fracturing, consistent with the DEP-approved water management plan (if applicable).
    - Depth of potable aquifers encountered during Drilling.
    - Whether methane was encountered at other than target formation during Drilling.
    - Radioactive or other industry standard logs, if appropriate.
    - Other information as required by DEP
- Well Stimulation and Completion Reports shall be posted on DEP's website.

10. To address deficiencies in the current bonding process, amend Section 215 as follows:
    - Raise Well bonding amounts for Unconventional Wells.
    - Prohibit blanket bonds for Unconventional Wells.
    - Allow the Environmental Quality Board, by regulation, to establish a voluntary Trust Fund Program as an alternative financial assurance mechanism.
        - Consideration should be given to adapting the Trust Fund mechanism from DEP's existing alternative trust fund program in the coal mining program.

11. To address concerns relating to sufficiency of Well Site inspections and enforcement, amend the Oil & Gas Act as follows:
    - Enhance inspections of Well Sites.
        - Expressly require DEP to inspect each Well Site as frequently as necessary to determine compliance with the law.
        - Require DEP to inspect each Well Site upon completion of erosion and sedimentation control measures, but prior to commencement of Drilling activity.
        - Require Well operators to provide notice to DEP, at least 24 hours in advance, before commencing the following activities at the Well Site:
            - Cementing of casing strings
            - Pressure testing of production casing strings
            - Well stimulation, including Hydraulic Fracturing
            - Plugging or abandoning of a Well
    - Require DEP to post all Well Site inspection reports online. Reports shall include:
        - Nature and description of violations, if any.
        - Operator's written response to violations, if available.
        - Status of violation.
        - Any remedial steps taken by the Well operator or DEP to address the violation.

12. Provide DEP with express authority to perform studies and prepare public reports on cumulative impacts to environmental resources and public health.

Addendum: Suggestions for Regional Planning and Participation

Local governments and counties are at the front line of unconventional shale gas development, and experience the most direct and consequential impacts. It is imperative that these interests be given greater support for planning and response, as well as more immediate involvement in the overall decision making process.

In developing our recommendations for amending the Oil & Gas Act, we have not had sufficient time to meet with these entities to truly understand their needs, or to craft precise policy or program recommendations to help address those needs. We urge the Governor's Marcellus Shale Commission and the General Assembly to make all efforts to better support local governments and counties as they continue to experience escalating shale gas development. At a minimum, that support should include the following:

1. Consideration of regionally-based comprehensive planning for well site and natural gas infrastructure development. This includes pipelines, compressor and metering stations, road building or repair, and water management systems (whether fresh water, or wastewater recycling or disposal).

2. Consideration of how counties can incentivize or even require, to the greatest extent practicable, consolidation of natural gas infrastructure development to reduce impacts to public or natural resources.

3. As part of reformation of the Oil & Gas Act permitting process outlined in Part Two of this proposal, provide counties with the right to appeal well permitting decisions of DEP to the Environmental Hearing Board.

4. Establish and fund a new statewide program to build the capacity of counties in areas involved in natural gas development that would allow those counties to: develop planning tools and information necessary to provide meaningful review of individual oil and gas permits; establish natural gas infrastructure development plans; and create a local natural gas development host inspector program. More specifically:
   - Planning: provide funding for the development and implementation of county zoning and comprehensive planning, including the further development of county natural resource plans and inventories, to allow counties to put together the information needed to evaluate oil and gas permits and infrastructure.
   - Permit Review: provide funding to allow the county to actively review and provide comments on individual well site permits and infrastructure development plans to DEP.
   - Host County Inspector: provide funding for host county natural gas development inspectors, certified and trained by DEP, to inspect gas well sites and gas infrastructure at any stage of its development for compliance with applicable state regulations. As with host inspectors under Act 101 of 1988 (Section 1102), these certified inspectors may have access to property and review records required by DEP to provide independent oversight of gas development operations.

Senator CARDIN. Mr. Ubinger, thank you very much for your testimony.

Mr. Cloud.

STATEMENT OF JEFF CLOUD, VICE CHAIRMAN, OKLAHOMA CORPORATION COMMISSION

Mr. CLOUD. Thank you very much, Mr. Chairman, Madam Chair Boxer and Ranking Member Inhofe, I very much appreciate the opportunity to visit with you today about the regulation of hydraulic fracturing and Oklahoma's many decades of experience in this regard. I ask that my corrected testimony be submitted in the record.

Senator CARDIN. Without objection, all of your statements will be included in the record.

Mr. CLOUD. Thank you.

The Oklahoma Corporation Commission was first given responsibility for regulation of oil and gas production in Oklahoma in 1914. Currently, the Commission has exclusive State jurisdiction over all oil and gas industry activity in Oklahoma, including oversight and enforcement of rules aimed at pollution prevention and abatement the State's precious water supplies.

Presently, there are over 185,000 wells in Oklahoma and thousands of miles of gathering and transmission pipelines. In recent years, the Woodford Shale in Oklahoma has become an important source of natural gas for the Nation. The development of Oklahoma's Woodford Shale, like other shale regions in the United States, has been made possible by horizontal drilling and hydraulic fracturing technologies.

Hydraulic fracturing, as Senator Inhofe said, has been used in Oklahoma for over 60 years and more than 100,000 Oklahoma wells have been hydraulically fractured over that period. Over that more than half-century of hydraulic frack experience, there has not been one single documented instance of contamination to groundwater or drinking water as a result of this process.

To say we take protection of our water quality seriously would be an understatement. Our rules are constantly reviewed and updated with that in mind. Our rules include a general prohibition against pollution of any surface or subsurface fresh water from well completion activities.

Oklahoma Corporation Commission rules address procedures in the event of unanticipated operational or mechanical changes. Standard Commission rules also require an operator to submit a well completion report within 30 days after completion of activities. The volumes of fluids used in this process are required on the form.

Last fall, the Oklahoma Corporation Commission volunteered to have its hydraulic fracturing program reviewed by a 12-year-old multi-stakeholder organization known as STRONGER or by its full name, State Review of Oil and Natural Gas Environmental Regulations. From October 2010 through January 2011, a seven-person again multi-stakeholder review team afforded by STRONGER conducted an in-depth examination of Oklahoma's hydraulic regulatory program.

The review team included Leslie Savage of the Texas Railroad Commission, Wilma Subra of Subra Company of New Iberia, LA and a noted critic of the domestic oil and gas industry, and Jim

Collins of the Independent Petroleum Association of America. Official observers included the Oklahoma Sierra Club and the U.S. Environmental Protection Agency Region VI.

The review team concluded that the Oklahoma program is overall well managed, professional and meets its program's objectives.

Incidentally, the U.S. EPA and the U.S. Department of Energy have provided grant funding to STRONGER to support its activities.

I would also note that in Oklahoma, collaboration involving the regulated oil and gas industry, other stakeholders and my State's agency staff have repeatedly led to successful development of rules and policies to address environmental protection issues, particularly the protection of water.

An example, there are two particular lakes that are exceptionally clean in Southeastern Oklahoma, Lake Atoka and McGee Creek Reservoir, that provide a very high quality water to the city of Oklahoma City about 100 miles away. But the lakes are also on top of deep rock deposits that hold huge amounts of natural gas, which in the best interests of Oklahoma and the Nation, we want to allow the petroleum industry to find and produce.

Without the need of any Federal intervention, the city of Oklahoma City, the regulated oil and gas industry and the State worked together to come up with acceptable protections because we all realize that it is in our mutual best interest to ensure proper and practical water and environmental protections, without cutting off access to critical resources.

Nature by itself unfortunately did not bless Oklahoma with any large natural bodies of water, so fresh water is especially precious in my State. Oklahoma has more than 50 man-made lakes and it is worth noting that Texas is currently suing Oklahoma in Federal Court to get our State's water. We must be doing something right.

All of us can agree that there needs to be rules of the road and that those rules need to be followed and enforced. We are making sure that those rules are followed and that Oklahoma's water and our environment are protected. Our record is clear that State regulation is the best way to meet those goals.

I and my two fellow Commissioners both hold elected statewide positions. We are directly accountable to our fellow Oklahomans and we all have a vested and personal interest in ensuring our water is protected. After all, and not be trite, we drink the water, too.

Thank you very much, Mr. Chairman.

[The prepared statement of Mr. Cloud follows:]

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TESTIMONY OF THE HONORABLE JEFF CLOUD
OKLAHOMA CORPORATION COMMISSION
VICE CHAIRMAN
BEFORE THE U.S. SENATE COMMITTEE ON ENVIRONMENT AND PUBLIC WORKS
AND SUBCOMMITTEE ON WATER AND WILDLIFE
JOINT HEARING
"NATURAL GAS DRILLING: PUBLIC HEALTH AND ENVIRONMENTAL IMPACTS"
TUESDAY, APRIL 12, 2011

I very much appreciate the opportunity to testify today before the joint hearing of the Senate Committee on Environment and Public Works and the Subcommittee on Water and Wildlife about the regulation of hydraulic fracturing and Oklahoma's many decades of experience in this regard.

Oklahoma's first commercial oil well was drilled in 1897, which was 10 years before Oklahoma officially became a state in 1907. Since then, oil and natural gas production has expanded into almost every part of the state.

The Oklahoma Corporation Commission (Commission) was first given responsibility for regulation of oil and gas production in Oklahoma in 1914. Currently, the Commission has exclusive state jurisdiction over all oil and gas industry activity in Oklahoma, including oversight and enforcement of rules aimed at pollution prevention and abatement and protecting the state's precious water supplies.

Presently, there are over 185,000 active wells in Oklahoma – roughly 115,000 oil, 65,000 gas and 10,500 injection/disposal wells – and thousands of miles of gathering and transmission pipelines.

In recent years the Woodford Shale in Oklahoma has become an important source of natural gas reserves for the nation. The development of the Oklahoma's Woodford Shale, like the other regions of shale development in the United States, has been made possible by improved horizontal drilling and hydraulic fracturing technologies.

Hydraulic fracturing has been used for over 60 years in Oklahoma, and more than 100,000 Oklahoma wells have been hydraulically fractured over that period. During more than half a century of hydraulic fracturing experience, there has not been a single documented instance of contamination to groundwater or drinking water as a result of hydraulic fracturing.

To say we take protection of our water quality seriously would be an understatement. Our rules are constantly reviewed and updated with protection in mind. Our rules include a general prohibition against pollution of any surface or subsurface fresh water from well completion activities.

Proper cementing and casing represent the primary means of protecting fresh water during hydraulic fracturing operations. Our agency created and continues to update a localized, detailed map of the state reflecting the base of treatable water. Prior to the start of drilling, each individual well permitted in Oklahoma is reviewed in conjunction with this map to ensure conformance with appropriate Commission rules for setting surface casing and other protections needed during drilling and completion. Production casing is required to be cemented a minimum of 200 feet above oil and gas producing zones and Commission field inspectors must be given at least 24 hours advance notice of cementing so that the inspector can witness that activity.

Commission rules address procedures in the event of unanticipated operational or mechanical changes that may be encountered during hydraulic fracturing and require the operator of the well to contact Commission officials within 24 hours of discovery of a casing problem. In addition to that notice, immediate remedial action is also required to repair any problems with surface or production casing.

A guidance document, referred to as the Commission "Guardian Guidance" has been developed and distributed widely. It provides the incremental process that an oil and gas operator should follow to assess, remediate if necessary and close any site that would be found to impact ground water or surface water.

As previously stated, Commission rules require operators to give 24-hour notice before setting surface casing or cementing surface strings. Standard Commission rules also require an operator to submit a well completion report within 30 days after completion activities. The volumes of fluids and proppants used in any hydraulic fracturing operation are required on the form. Commission rules also allow the agency to obtain information identifying chemicals used in hydraulic fracturing or other exploration and production operations.

In August of 2010, the Commission volunteered to have its hydraulic fracturing program reviewed by a 12-year-old multi-stakeholder organization known as STRONGER, or, by its full name, State Review of Oil & Natural Gas Environmental Regulations. The Oklahoma oil and gas regulatory program had undergone three successful prior reviews.

From October 2010 through January 2011, a seven-person, multi-stakeholder review team appointed by STRONGER conducted an in-depth examination of Oklahoma's hydraulic regulatory program. The review team included Leslie Savage of the Texas Railroad Commission; Wilma Subra, of Subra Company of New Iberia, Louisiana (and a noted critic of the domestic oil and gas industry); and Jim Collins of the Independent Petroleum Association of America. The official observers included the Oklahoma Sierra Club and the United States Environmental Protection Agency Region VI.

The review team concluded that the Oklahoma program is, overall, well managed, professional and meets its program objectives. Incidentally, the U.S. Environmental Protection Agency and U.S. Department of Energy have provided grant funding to STRONGER to support its activities.

I would also note that in Oklahoma, collaboration involving the regulated oil and gas industry, other stakeholders and my state agency's Staff have repeatedly led to successful development of rules and policies to address environmental protection issues, particularly the protection of water.

An example: In 2008 the Commission modified and expanded rules over oil and gas industry activity to control runoff of soil and dissolved minerals and chlorides into the watershed that feeds two vital southeast Oklahoma lakes.

The two particular lakes that I mentioned – Lake Atoka and McGee Creek Reservoir – are exceptionally clean and provide very high quality water to the City of Oklahoma City about 100 miles away. But the lakes also are on top of deep rock deposits that hold huge amounts of natural gas, which, in the best interest of Oklahoma and the nation, we want to allow the petroleum industry to develop and produce.

The rules established in 2008 replaced out-dated 1985 field rules that were developed at a time when there was much less oil and gas industry activity in that part of the state. The new rules were hammered out over several meetings involving representatives of Oklahoma City's water utility division, the oil and gas industry, rural water districts, counties, tribal governments, our agency's regulatory enforcement Staff and other stakeholders.

These revised rules modified requirements for setbacks (buffer zones) from lakes, retaining walls or berms around wellsites, pit liners and operations for muds and fluids used and produced during drilling operations and for other requirements to provide flexibility needed by industry while increasing protection of water resources.

Such rules allow the oil and gas industry to continue to pursue its important goal of finding and producing critical natural energy resources, while also providing added measures to ensure the quality of lake waters and environment are protected.

Moreover, each year, the Commission conducts a detailed rulemaking process where Commission rules are reviewed and revised on an ongoing basis to keep up with changing technology, statutes and environmental concerns. Notice is given to the public and all interested stakeholders through published newspaper notices and posted open meetings. Our staff of experienced geologists, hydrologists and others are continually involved in this rulemaking process in addition to regularly working with the public and landowners to address potential environmental concerns.

Without the need for any federal intervention, the City of Oklahoma City, the regulated oil and gas industry and the State worked together to come up with acceptable protections because we all continue to recognize it is in our mutual best interest to ensure proper and practical water and environmental protections without cutting off access to critical resources.

Nature by itself unfortunately did not bless Oklahoma with any natural large bodies of water, so fresh water is especially precious in my state. Oklahoma has more than 50 man-made lakes. It is worth noting that Texas is currently in court suing Oklahoma to get our state's water. We must be doing something right.

All of us can agree that there need to be "rules of the road" and that those rules need to be followed and enforced. The issue is what works best in making sure that those rules are followed and that Oklahoma's water and our environment are protected.

Oklahoma's record makes it clear that state regulation is the best way to meet those goals.

I and my two fellow Commissioners hold elected positions. We are directly accountable to our fellow Oklahomans. We have both a vested and personal interest in ensuring our water is protected. After all, and not to be trite, we drink the water, too.

Environment and Public Works Committee Hearing
April 12, 2011
Follow-up Questions
Answers Provided by Oklahoma Corporation Commissioner Jeff Cloud

Question from Senator Boxer:

1. Can you explain why Oklahoma prohibits the discharge of process wastewater to surface waters and how the State is successfully managing the disposal of the wastewater in underground injection wells regulated under the SDWA?

Corporation Commission rules prohibit the discharge of exploration and production wastewaters to surface waters unless the Commission issues an order approving an exception. The Commission has approved no exceptions to the general prohibition.

As a practical matter, produced waters from oil and gas wells in Oklahoma tend to have a high salt content and most streams have inadequate flow to handle the additional salt load. Discharge of produced waters under these circumstances would cause a violation of water quality standards. Also, Oklahoma has a well established infrastructure of disposal wells with adequate capacity to handle the wastewaters associated with oil and gas exploration and production operations. These injection wells are widely recognized as the safest and easiest means of disposal.

The Corporation Commission first began permitting wells for underground injection in the 1930's. In 1981 the Commission became the first state agency in the country to receive primacy from the EPA to administer the Class II UIC program under the Safe Drinking Water Act. Over the years we have continued to review and revise our regulations in order to incorporate technological advances and maintain a sound program. Having a well established permitting and monitoring program in addition to experienced personnel to implement the program have contributed to our success.

Environment and Public Works Committee Hearing
April 12, 2011
Follow-up Questions
Answers Provided by Oklahoma Corporation Commissioner Jeff Cloud

Questions from Senator Inhofe:

1. Would you walk me through Oklahoma's permitting process for natural gas drillers? In your opinion, are states adeqately equipped to regulate HF?

The report recently released by STRONGER on its review of the Oklahoma hydraulic fracturing regulations provides detailed information on the Corporation Commission's permitting, reporting, inspection and enforcement processes for natural gas drillers. This report is entitled "Oklahoma Hydraulic Fracturing State Review," and is available at www.strongerinc.org. In particular, the completed questionnaire that appears as Appendix B of the report contains our description of how we regulate hydraulic fracturing operations in Oklahoma. This appendix includes a copy of Corporation Commission Rule 165:10-3-10, which provides a rule reference guide to 35 separate rules applicable to hydraulic fracturing operations in the state.

The body of the STRONGER report provides the assessment of the Oklahoma program by a stakeholder review team that included representatives of regulatory agencies, environmental organizations, and industry. The findings of the Oklahoma review and similar reviews conducted in other states show that the states are well equipped to regulate hydraulic fracturing. These reports also document that each state has experienced challenges in regulating hydraulic fracturing, that the specific nature of the challenges varies from state to state, and that each state has taken action in a manner appropriate to its particular circumstances to ensure that hydraulic fracturing operations are conducted safely.

2. The oil and gas industry is ever-evolving with the advent of new technologies and drilling and production techniques. Could you discuss the process for which your agencies review and update regulations to ensure that the proper safeguards are in place to protect human health and the environment?

For many years, the Corporation Commission has engaged in an annual process of review and revision of its oil and gas rules. Each year, with assistance from stakeholder workgroups, the Commission evaluates how the current rules are working, analyzes emerging issues, considers the impact of new technologies, and drafts new rules or rules amendments. Based on the results of this review, the staff prepares a rulemaking package for consideration by the Commission following a public comment period. Through this process of continuing assessment and improvement, the Commission ensures that its rules remain current and effective.

3. In your testimonies, you state that you are not aware of groundwater contamination from hydraulic fracturing in your States. Why do you think hydraulic fracturing has gotten so

much attention? In the framework of regulatory and environmental challenges you each face, are the claims of environmental damage due to hydraulic fracturing justified?

Horizontal drilling coupled with multi-stage hydraulic fracturing has enabled the development of natural gas reservoirs that were not previously considered viable resources. As a consequence of this revolutionary advance in technology, drilling is occurring in parts of the country that have not seen this type of development in the past. The local communities, which are experiencing something new and do not understand the technologies involved, have concerns about potential environmental impacts.

Hydraulic fracturing, if not conducted carefully, has some potential to cause environmental damage, especially if fluids associated with hydraulic fracturing are not properly managed at the surface. Agencies like the Corporation Commission have established rules to ensure that hydraulic fracturing operations are conducted safely and associated fluids are handled responsibly. We also have rules requiring remedial action to be taken in the event a problem occurs. In our experience, these rules have worked effectively to prevent contamination of our water resources and protect our environment.

4. Is there anything else you would like to add for the record?
   Thank you for the opportunity to respond, I have nothing further to add at this time.

Environment and Public Works Committee Hearing
April 12, 2011
Follow-up Questions
Answers Provided by Oklahoma Corporation Commissioner Jeff Cloud

Questions from Senator Cardin:

1. Has the Oklahoma Corporation Commission undertaken any studies relating to the potential for seismic activity as a result of drilling? How much information does OCC have about the underlying geologic formation in the state? Does it have enough information to scientifically evaluate the potential geologic impacts that expansive drilling activity may have?

A modern seismic network has monitored seismic activity in Oklahoma since the 1970's. Swarms of small, naturally occurring earthquakes are not an unusual occurrence in the state. In 2010, Oklahoma recorded 1,047 earthquakes, about 700 of which occurred in eastern Oklahoma County, where there has not been much recent oil and gas industry activity such as hydraulic fracturing. The Oklahoma Geological Survey is the state entity that monitors and investigates seismic activity. The Survey is studying the question whether any seismicity observed in the state has been triggered by oil and gas production activities. The Survey has advised us that scientists should assume that, until data indicates otherwise, seismicity occurring within the mid-continent area is naturally occurring.

The Corporation Commission and other state agencies, universities, and geological societies in the State of Oklahoma have a large, continually expanding body of information about the underlying geologic formations and fresh water aquifers in the state. This information comes from the records of hundreds of thousands of oil and gas wells and water wells drilled in the state over more than a century. Scientists and geotechnical professionals use this information in preparing applications and conducting investigations concerning geologic impacts of drilling activity.

2. In your professional judgment, should wastewater treatment facilities be allowed to accept these kinds of waste streams for treatment and discharge into surface waters?

My response to Senator Boxer's question discusses the reasons exploration and production wastewaters may not be discharged to surface waters in Oklahoma. I cannot speak for other regions of the country. The decision whether to allow wastewater treatment facilities to accept these kinds of waste streams for treatment and discharge into surface waters depends on factors that vary from one region to another and from one waste stream to another. For example, in arid parts of the country, EPA's NPDES (National Pollutant Discharge Elimination System) regulations allow some oil and gas produced waters to be treated and discharged to streams for agricultural and wildlife purposes. If properly controlled, this type of discharge serves a beneficial purpose.

Senator CARDIN. Thank you very much for your testimony.

Mr. Neslin.

STATEMENT OF DAVID NESLIN, DIRECTOR, COLORADO OIL AND GAS CONSERVATION COMMISSION

Mr. NESLIN. Thank you.

Mr. Chairman, Ranking Member Inhofe, other Members of the committee, thank you for the opportunity to provide our perspective on how Colorado protects public health and the environment while we develop our oil and gas resources.

My name is David Neslin. I am the director of the Colorado Oil and Gas Conservation Commission. We are a major oil and gas-producing State with a rich natural heritage and a thriving outdoor economy.

I want to focus my comments today on the subject of hydraulic fracturing.

Most of Colorado's 44,000 oil and gas wells, as well as the thousands of new wells that will be drilled in the coming years, rely on hydraulic fracturing. This technology is vital to unlocking our rich oil and gas reserves which are a critical source of domestic energy and provide good-paying jobs and needed tax revenues to our communities.

But it is also essential that this development occurs in an environmentally responsible manner that protects our drinking water. This is a fundamental part of our regulatory mission and it is something that everyone at our agency takes very seriously.

To this end, our environmental professionals have investigated hundreds of groundwater complaints over the years. To date, we have found no verified instance of hydraulic fracturing harming groundwater. These investigations are all publicly available.

We have also required operators to test water quality repeatedly and over time in more than 1,900 water wells in one of our most productive natural gas fields. Thousands of nearby oil and gas wells have been hydraulically fractured and if fracturing fluids were reaching those water wells, then you would expect the water's chemical composition to change. But independent analysis has found not statistically significant changes to those waters. This analysis is likewise publicly available.

In addition, we have comprehensively updated our regulation to address a broad range of environmental issues. Our current rules strike a responsible balance between energy development and environmental protection, and they reflect substantial input from local governments, oil and gas companies, environmental groups and thousands of individuals from across our State.

Other States have taken or are taking similar action, including Wyoming, Oklahoma, Ohio, Pennsylvania, and Arkansas. These recent State rulemakings exemplify the benefits associated with State oversight and site-specific regulation, and they specifically address hydraulic fracturing.

In Colorado, for example, wells must be cased and cemented to protect aquifers and well pressures must be monitored during hydraulic fracturing. Operators must inventory chemicals including hydraulic fracturing fluids and provide this information upon request to the State and certain health care professionals.

There are mandatory setbacks and enhanced environmental protections for oil and gas development near public drinking water sources. Additional pressure testing, well testing, water well sampling is required for shallow of cold-bed methane wells. Enhanced requirements apply to pit permitting, pit lining, pit monitoring, to ensure that waste, including any flow-back of hydraulic fracturing fluids, is properly contained.

Now, these regulations are important and they have substantially improved our groundwater protection, but we haven't stopped there. We are continuing to take proactive, cost-effective steps to ensure that hydraulic fracturing protects public health and the environment.

First, we and other States have worked closely with the Groundwater Protection Council on the launch of the new Website fracfocus.org. This site encourages oil and gas operators to voluntarily provide information on the chemicals they use to hydraulically fracture a well and complements our own regulatory framework.

Second, we have arranged to have our hydraulic fracturing regulations professionally audited this summer by STRONGER, a national organization consisting of State regulators and industry and environmental representatives. STRONGER recently completed similar reviews of Oklahoma, as you have heard, as well as Pennsylvania, Ohio and Louisiana. We are having them review Colorado's program to determine whether further improvements can be made at our end.

Third, we are actively investigating the alleged use of diesel fuel or fluids containing diesel fuel for hydraulic fracturing in Colorado. While we believe that our regulations would have prevented contamination of drinking water supplies, we are collecting information to independently assess that issue.

Fourth, we continue to address public concerns on this issue in an open and transparent manner. Just this last February, our Commission convened a full public hearing to examine an allegation of water well contamination. In that case, our Commissioners, a diverse board representing environmental, industry, local government, and other sectors, unanimously determined that hydraulic fracturing had not impacted the well in question.

In summary, I want to stress how seriously we take this subject and that many other States are taking similar action. Our experience and that of other States demonstrates how hydraulic fracturing and other oil and gas activities are effectively regulated at the State level where highly diverse regional and local conditions are more fully understood and where rules can be tailored to fit the needs of local basins, local landscapes and local communities.

Thank you.

[The prepared statement of Mr. Neslin follows:]

David Neslin
Director, Colorado Oil and Gas Conservation Commission
Testimony before the U.S. Senate Committee on Environment and Public Works &
Subcommittee on Water and Wildlife

"Natural Gas Drilling: Public Health and Environmental Impacts"

Tuesday, April 12, 2011

Madame Chair, thank you for this opportunity to provide our perspective on how the state of Colorado is protecting public health and the environment while we develop our important, indigenous oil and gas resources. My name is David Neslin, and I am the director of the Colorado Oil and Gas Conservation Commission, the state agency responsible for regulating oil and gas development. I thank you and your colleagues for your thoughtful consideration and your efforts to gather the information necessary to properly evaluate these matters.

Colorado has a long and proud history of oil and gas development, with our first oil well dating back to 1862. As of 2009, we ranked fifth in natural gas production and tenth in oil production. Our diverse hydrocarbon resources encompass a variety of shale, tight sand, coal bed methane, and other formations that span the state. At the same time, we have a thriving resort and tourist economy, and our rugged mountains, clear streams, and abundant wildlife are an essential part of our heritage.

I want to focus most of my comments today on hydraulic fracturing, as it remains at the center of discussion on oil and gas drilling both in Colorado and nationally. Most of Colorado's 44,000 active oil and gas wells, as well as the thousands of new wells that will be drilled in the coming years, rely on hydraulic fracturing to create the permeability that allows fluid and gas to flow into the wellbore and be produced. It is not an understatement to say that this technology is absolutely vital to unlocking Colorado's rich natural gas and oil reserves. These reserves are a critical source of domestic energy for our state and nation, and their exploration, development, and production provides good-paying jobs for our residents and needed tax revenues for our communities.

But it is also essential that this development occurs in an environmentally responsible manner that protects our water resources generally and our drinking water specifically. This is a fundamental part of our regulatory mission, and something that everyone at our agency takes very seriously. To this end, our environmental professionals have investigated hundreds of groundwater complaints over the years. To date, we have found no verified instance of hydraulic fracturing harming groundwater. These investigations have been documented and are publicly available on our website.

In addition, since 2000, our Commission has required operators to collect pre- and post-development water quality samples from more than 1,900 water wells in the San Juan Basin in Southwestern Colorado, which has historically been one of our most productive natural gas-producing areas. Thousands of oil and gas wells in that Basin have been hydraulically fractured, and if fracturing fluids were reaching these water wells then you would expect changes in the chemical composition of the water. However, independent analysis of the data has found no statistically significant increase in chemical concentrations. A report documenting this analysis is likewise available on our website, and we have offered to share this data with the Environmental Protection Agency. We have also collected or required operators to collect similar data from about another 1,900 water wells in other gas and oil producing areas of the state.

I would also like to emphasize that during 2007 and 2008, our agency devoted substantial time and effort to updating our regulations to address a broad range of environmental issues associated with oil and gas development. This rulemaking process lasted 16 months, included testimony from 160 witnesses, and involved 22 days of hearings. The final rules strike a responsible balance between energy development and environmental protection, and they reflect input from dozens of local governments, oil and gas companies, and environmental groups, as well as thousands of our residents. And many other states have subsequently taken or are taking similar action, including Wyoming, Oklahoma, Ohio, Pennsylvania, and Arkansas.

These recent state rulemakings exemplify the benefits associated with state oversight and site-specific regulation, and they have specifically addressed hydraulic fracturing concerns. Colorado's amended rules contain various provisions to ensure that such activities do not harm our drinking water while recognizing the variety of issues at play in different regions of our state. For example,

- Rule 205 requires operators to inventory chemicals kept at drilling sites, including hydraulic fracturing fluids. This information must be provided to agency officials promptly upon request and also to certain health care professionals who sign a confidentiality agreement. This allows government officials and medical professionals to investigate and address allegations of chemical contamination associated with hydraulic fracturing, while protecting proprietary information.
- Rule 317 requires wells to be cased with steel pipe and the casing to be surrounded by cement to create a hydraulic seal and ensure that gas and fluids do not leak into shallower aquifers. Further, operators are required to run cement bond logs on all production casing to confirm that the cement has properly isolated the hydrocarbon bearing zones. Rule 341 requires operators to monitor well pressures during hydraulic fracturing and promptly report significant increases. Together, these requirements help to ensure that ground water is protected and that prompt action is taken if conditions arise that could lead to the subsurface release of hydraulic fracturing fluids.

- Rule 317B imposes mandatory setbacks and enhanced environmental protections on oil and gas development occurring near sources of public drinking water. These requirements provide an extra layer of protection for our public water supplies and help ensure that these critical resources are not inadvertently contaminated by energy development.
- Rule 608 requires operators developing coalbed methane wells to pressure test the wells and to sample nearby water wells before, during, and after operations to ensure that they are not contaminated by gas or other pollutants. Rule 318A requires operators in the DJ Basin in northeastern Colorado to do similar water well sampling before drilling. These rules provide an extra layer of protection for water wells located near oil and gas development.
- Rules 903, 904, and 906 impose updated requirements for pit permitting, lining, monitoring, and secondary containment to ensure that fluids in pits do not contaminate soil, groundwater, or surface water. These requirements will help ensure that any flowback of hydraulic fracturing fluids is properly contained.

These regulations are important, and we believe they have substantially improved our protection of water resources. But we have not stopped there. We are continuing to take proactive, cost-effective steps to ensure oil and gas development, and hydraulic fracturing in particular, protects public health and the environment. Let me address these here.

First, we and other states have worked closely with the Groundwater Protection Council and the Interstate Oil and Gas Compact Commission on the launch of a new website – www.fracfocus.org. This site, launching this week, encourages oil and gas operators to voluntarily provide information on the chemicals they use to hydraulically fracture a well. As you know, this has been a sensitive issue for the public and the industry, and we believe this on-line chemical registry will provide helpful information to citizens who want to better understand hydraulic fracturing or have questions about a particular well. Under our regulations that took effect in 2009, operators already must disclose fracturing constituents upon request by state regulators or health professionals. The website will compliment this requirement by providing a wealth of information to the public, including company names, well locations, construction details, fracturing fluid constituents, and chemical abstract numbers.

Second, we have arranged to have our hydraulic fracturing regulations professionally audited this summer by STRONGER – The State Review of Oil & Natural Gas Environmental Regulations. STRONGER is a national organization consisting of state regulators and industry and environmental representatives. Their review process is a collaborative undertaking involving an evaluation of our regulations and a comparison of them against a set of guidelines developed and agreed to by all participating parties. During the last eight months, STRONGER completed similar reviews of the Oklahoma, Pennsylvania, Ohio and Louisiana hydraulic fracturing programs, and we are subjecting Colorado's program to a STRONGER review to determine whether further improvements can be made.

Third, the House of Representatives Committee on Energy and Commerce recently reported that about 1.3 million gallons of diesel fuel or fluids containing diesel fuel was used for hydraulic fracturing in Colorado during the period from 2005 through 2009. In response, we have launched our own investigation into this subject. This work involves both reviewing our own records as well as gathering information from service companies and operators. While we believe our regulations would have prevented contamination of drinking water supplies, we are collecting information independently to assess the situation.

Fourth, we continue to consider and assess public concerns that have arisen over hydraulic fracturing. As part of this, we have endeavored to give these matters the transparency they require and deserve. In February of this year, our Commission held a full public hearing to examine an allegation that hydraulic fracturing had contaminated a water well in southern Colorado. In this case, our Commissioners – a diverse board representing environmental, industry, local government and other sectors – unanimously determined that hydraulic fracturing had not impacted the well in question.

In summary, I want to stress how seriously we take this subject, and how Colorado is committed to ensuring that hydraulic fracturing protects public health and the environment. I also want to note that we are not unique, and that many other states are taking similar action. Our experience, and that of other states, demonstrates how hydraulic fracturing and other oil and gas activities are most effectively regulated at the state level, where highly diverse regional and local conditions are more fully understood and where rules can be tailored to fit the needs of local basins, environments and communities. In this way, we can ensure that our precious natural resources and environment are protected while providing our state and nation with a cleaner burning and vital source of domestic energy and allowing for the innovation and experimentation that are the hallmarks of our nation.

STATE OF
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GAS
CONSERVATION COMMISSION

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David Neslin
Director, Colorado Oil & Gas Conservation Commission
Written Answers to Follow-Up Questions from the
Senate Committee on the Environment and Public Works
Submitted May 17, 2011

Questions from Senator Barbara Boxer:

1. During your testimony before the Committee, you stated that nearly all of the natural gas wells drilled in Colorado involve horizontal drilling and hydraulic fracturing. In your written testimony, you state the COGCC has investigated hundreds of allegations of groundwater contamination from natural gas drilling operations in Colorado, but that "[t]o date, we have found no verified instance of hydraulic fracturing harming groundwater." During the hearing, you indicated that your agency has found instances where groundwater has been contaminated from a spill, leak or failure of a cement job.

   Question. Do you agree that the use of hydraulic fracturing greatly increases the pressures on a gas well, including the casing, the cementing, and the blowout preventer?

   Answer. Hydraulic fracturing involves injection pressures that exceed those of the geologic formation. In practice, however, the well casing, cementing, and blowout preventer are all designed to manage these pressures. In Colorado, regulations adopted by the Oil & Gas Conservation Commission ("COGCC") further require that the well components manage these pressures. COGCC Rule 317.a states that the "working pressure of any [blowout preventer] shall exceed the anticipated surface pressure to which it may be subjected." Rule 317.d mandates that well casings be "planned and maintained" to "prevent the migration of oil, gas or water from one (1) horizon to another." Rules 317.g and 317.h set forth specific cementing requirements. And Rule 317.j requires production casing to be "adequately pressure tested for conditions anticipated to be encountered during completion and production operations."

   I would also like to clarify that to date relatively few natural gas wells drilled in Colorado have involved horizontal drilling.

   Question. Do you agree that hydraulic fracturing greatly increases the volumes of liquids which must be properly managed?

   Answer. Oil and gas development typically involves large volumes of liquids, which may include liquid hydrocarbons, produced water, and fracturing fluids. We estimate that fracturing fluids constitute about 9% of the total liquids generated by or used for oil and gas development. To ensure that all such liquids are properly managed, Colorado has adopted a variety of regulations, including COGCC Rules 206 (compliance checklists), 209 (protection of water-bearing formations), 317 (general drilling operations), 317A (special drilling operations), 317B (public water system protection), 324A (pollution prevention), 604 (oil and gas facilities), 608 (coalbed methane wells), 902 (general and special pits), 903 (pit permitting), 904 (pit lining), 905 (pit closure), 907 (waste management), 908 (centralized waste management), 1002 (stormwater management), and 1003 (interim reclamation). These regulations were comprehensively updated in 2008.

Question. Do you agree that the increases in well pressures during hydraulic fracturing operations can increase the risk of failure of the well casing, the cement job, and the blowout preventer?

Answer. As explained above, the well casing, cement job, and blowout preventer are designed to manage the hydraulic fracturing pressures, and Colorado has adopted regulations that require the well components to manage such pressures. For example, COGCC Rule 317.j requires pressure testing of the production casing for pressures anticipated during well completion, which would include fracture treatment. In addition, Rule 341 requires bradenhead annulus pressures to be "continuously monitored and recorded" during hydraulic fracturing and verbal notice to be given to the COGCC "as soon as practicable if the bradenhead annulus pressure increases by more than 200 psig."

Question. Do you agree that groundwater contamination from a spill, leak, or failure of a cement job present public health and environmental threats and must be addressed in natural gas drilling operations?

Answer. Groundwater contamination from a spill, leak, or failure of a cement job presents a threat to public health and the environment and must be addressed in drilling operations. As explained above, Colorado has adopted a variety of regulations to address such risks, and these regulations were comprehensively updated in 2008 to reflect current conditions and best practices. Additional regulations that address groundwater contamination include COGCC Rules 906 (spills and releases), 909 (investigations and remediations), and 910 (concentrations and sampling). Under these updated regulations, Colorado operators are improving their water management. For example, the percentage of well pads utilizing closed loop or pitless drilling systems has increased from 31% in January 2010 to 79% in March 2011.

2. COGCC investigated the Ellsworth drinking water well in Weld County Colorado and found that the Ellsworth well has been contaminated by a mixture of biogenic (natural) and thermogenic (from gas drilling operations) contaminants. Although there were a number of gas wells drilled near the Ellsworth drinking water well, COGCC was unable to determine the particular source because the leaking well may have been fixed and the mixture of biogenic and thermogenic sources made it impossible for COGCC to "fingerprint" the source well. One of the companies responsible for the drilling entered into a voluntary agreement with the Ellsworth's for replacement water.

Question. Do you agree that this is a verified case of gas drilling operations causing groundwater contamination, even though the particular well that caused the contamination was never determined?

Answer. As the COGCC reported in 2008, the methane contamination found in the Ellsworth water well included thermogenic methane that appeared to be from oil and gas activity. The COGCC could not, however, attribute this methane to gas drilling operations as opposed to subsequent well production.

3. COGCC took enforcement action against Encana relating to its Schwartz 2-15B Well (Enforcement Order 1V-276), after an investigation determined that Encana had performed hydraulic fracturing operations 4 times without notifying COGCC that its cement job had failed (the cement top had fallen), resulting in ground and surface water contamination.

   Question. Do you agree that this is a verified case of gas drilling operations causing groundwater contamination?

   Answer. The Schwartz 2-15B Well is a verified case of groundwater contamination caused by gas drilling operations, specifically, the failure of a cement job. This episode led the COGCC to impose additional well cementing, testing, and reporting requirements in the vicinity of the Schwartz 2-15B Well. The COGCC also amended Rule 317.o to require all operators in Colorado to run cement bond logs to ensure that proper cement coverage is achieved on all production casing.

   Question. Even though the failure of the cement job was the direct cause of the contamination, do you agree that the fact that EnCana performed completion operations that included hydraulic fracturing and flowback water 4 times after the cement top had fallen was a significant contributing factor to the resulting groundwater contamination?

   Answer. The COGCC's investigation determined that the groundwater contamination was not caused by hydraulic fracturing. This determination was based upon the following factors: bradenhead pressures during hydraulic fracturing showed no communication above the top of the cement; normal fracture treatment pressure showed containment of the fracturing fluids within the target zone; no indication of fracturing fluids was detected in the groundwater samples; and the gas seep decreased after remedial cementing of the well, which would not have occurred if hydraulically induced fracturing had caused the seep.

Question from Senator Benjamin L. Cardin:

1. The refinement of advanced drilling technologies has led to a significant increase in drilling activities. As drilling has boomed, some geographic locations have experienced unusual seismic activity. For example, Arkansas has recently experienced an earthquake swarm, with about 1,000 earthquakes occurring since September 2010. Some had suggested that this unusual seismic activity is related to natural gas drilling operations.

Has the Colorado Oil and Gas Conservation Commission undertaken any studies relating to the potential for seismic activity as a result of drilling? How much information does COGCC have about the underlying geologic formations in the state? Does it have enough information to scientifically evaluate the potential geologic impacts that expansive drilling activity may have?

Answer. Colorado is very familiar with "induced seismicity" related to human activity tied to a variety of processes, including the deep underground injection of waste. The Colorado Geological Survey and the Colorado School of Mines, as well as the University of Colorado, have a wealth of data on these matters and the COGCC can and does turn to these institutions for assistance. These institutions have identified no notable induced geological impacts from the many thousands of oil and gas wells in Colorado that have been fractured to date.

Questions from Senator James M. Inhofe:

1. Would you walk me through Colorado's permitting process for natural gas drillers? In your opinion, are states adequately equipped to regulate HF?

   Answer. Anyone seeking to drill a natural gas well in Colorado must submit a Form 2, Application for Permit to Drill ("APD"), under COGCC Rule 303.a. The APD includes information on the well location, formations and spacing, and drilling plans and procedures, including the casing, cementing, and blowout preventer. This information is reviewed by engineers and permit technicians at the COGCC, and additional conditions are imposed where necessary to protect public health and the environment.

   Applicants must also submit a Form 2A, Location Assessment, for the well pad and certain related facilities under COGCC Rule 303.b. The Assessment includes additional information on the location, including information on major equipment, nearby improvements, surface water, access roads, land use, and soils. This information is reviewed by environmental professionals at the COGCC, and again additional conditions are imposed where necessary to protect public health and the environment.

   All Location Assessments and associated APDs are subject to public notice and at least 20 days of public comment under COGCC Rule 305. In addition, special notice of such filings is provided to the local government, the surface owner, and, across most of the state, the owners of surface property within 500 feet.

   Operators are also required to consult with the surface owner and the local government in locating certain facilities under COGCC Rule 306. If a proposed well pad is located in important wildlife habitat, then the COGCC will consult with the Colorado Division of Wildlife. If the operator seeks a variance from certain environmental regulations or the local government requests, then the COGCC will consult with the Colorado Department of Public Health and Environment.

Following staff review and any consultation and public comment, Location Assessments and APDs are approved by the COGCC Director. The COGCC may attach technically feasible and economically practicable conditions of approval under COGCC Rule 305, and, as noted above, the COGCC often does so to protect public health and the environment. In addition, applicants must provide financial assurance to the State under COGCC Rule 304 and the 700 Series of COGCC Rules. Following the drilling and completion of the well, additional reporting requirements apply under COGCC Rules 308A, 308B, and 309.

In my opinion, Colorado and those states with which I am familiar are adequately equipped to regulate hydraulic fracturing. As I previously testified, Colorado will continue to take appropriate action to ensure that such regulation is effective and efficient.

2. The oil and gas industry is ever-evolving with the advent of new technologies and drilling and production techniques. Could you discuss the process for which your agencies review and update regulations to ensure that the proper safeguards are in place to protect human health and the environment?

   Answer. As noted above, the COGCC comprehensively updated its regulations in 2008 to improve protection of public health and the environment. The COGCC has described this rulemaking process as follows:

   > "All told, the Commission held twenty-two days of hearings, with some [of] the days lasting almost twelve hours. The Commission heard approximately twelve hours of public comment by approximately two hundred people. It heard from approximately one hundred sixty party and staff witnesses and heard approximately seventy-five hours of testimony, cross, examination, and answers to Commissioner questions on twelve days of hearings. The Commission also considered more than thirty legal motions and conducted nine days of initial and final deliberations totaling more than seventy additional hours. Throughout the hearing, the Commission listened to all of the witnesses, questioned aspects of witnesses' written testimony, directed its staff to work with parties, and asked clarifying questions as necessary. The Commission repeatedly extended the rulemaking hearing in order to hear additional testimony and argument and conduct additional deliberations. It also directed and approved numerous changes to the draft rules that reflect input from the parties."

   In addition, the COGCC has updated its regulations on approximately 40 other occasions since 1990 to address changes in environmental laws, demographics, distribution of oil and gas activities, and potential environmental impacts.

3. In your testimonies, you state that you are not aware of groundwater contamination from hydraulic fracturing in your States. Why do you think hydraulic fracturing has gotten so

much attention? In the framework of regulatory and environmental challenges you each face, are the claims of environmental damage due to hydraulic fracturing justified?

Answer. Hydraulic fracturing, while practiced for decades, is new in many parts of the country. Even where it is not new, it's now deployed commonly as part of natural gas development. We believe much of the attention stems from the fact that, to many, it is a new and unfamiliar technique. The features of fracturing – cracking rock deep underground using high pressures and a relatively small amount of chemicals – have created fears for some that this process could perhaps lead to the migration of chemicals into water supplies. We take the protection of water supplies very seriously, and understand that the public wants assurances that, in fact, such impacts will not occur. In our own experience, we have not found any instances where the process of hydraulic fracturing has contaminated water supplies. To be sure, we have found other instances where activities associated with oil and gas operations have impacted water supplies. These events have typically been tied to incidents such as a leaking storage pit, a poorly cemented oil and gas well, or leaking production equipment. These cases, however, have not been linked to the specific act of hydraulically fracturing hydrocarbon layers thousands of feet below the surface, and typically, thousands of feet below groundwater supplies.

4. Is there anything else you would like to add for the record?

Answer. Attached are the following COGCC documents, all of which are available on our website and provide support for the answers set forth above:

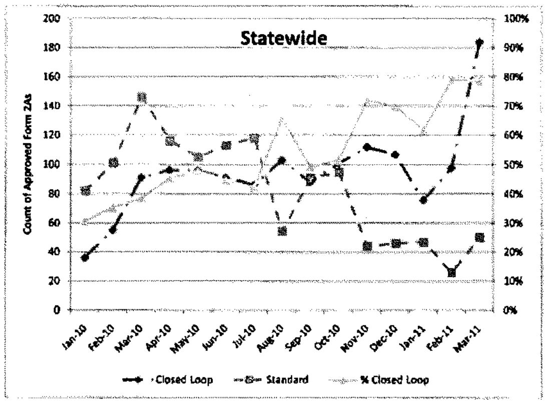
- Closed Loop Drilling System Data (May 16, 2011);
- Gasland Correction Document (September 2010);
- Report on the Ellsworth Water Well Investigation (August 7, 2009);
- Excerpt from the Statement of Basis, Specific Statutory Authority and Purpose for the New Rules and Amendments Adopted by the COGCC (December 11, 2008); and
- COGCC Staff Presentation on Why the West Divide Creek Gas Seep was Not Caused by Hydraulic "Fracing" From the Hearing on the Schwartz 2-15B Well (August 16-17, 2004).

Use of Closed Loop Drilling Systems

As Reported or Conditioned on the Oil and Gas Location Assessment, Form 2A
January 2010 through March 2011

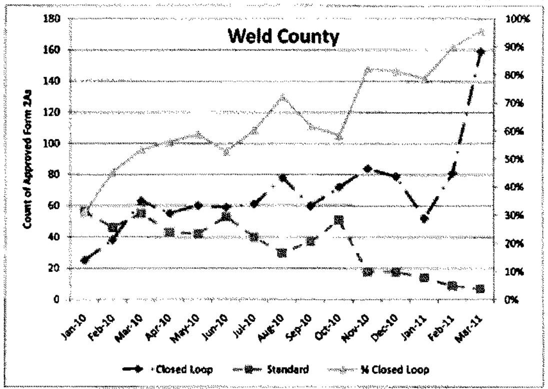
Statewide

Date	Closed Loop	Standard	% Closed Loop
Jan-10	36	82	31%
Feb-10	55	101	35%
Mar-10	91	146	38%
Apr-10	96	116	45%
May-10	96	105	48%
Jun-10	91	113	45%
Jul-10	86	118	42%
Aug-10	103	54	66%
Sep-10	88	91	49%
Oct-10	101	95	52%
Nov-10	112	44	72%
Dec-10	107	46	70%
Jan-11	76	47	62%
Feb-11	98	26	79%
Mar-11	184	50	79%



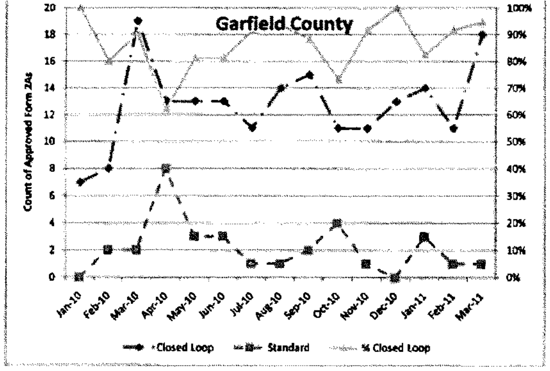
Weld

Date	Closed Loop	Standard	% Closed Loop
Jan-10	25	56	31%
Feb-10	38	46	45%
Mar-10	63	55	53%
Apr-10	55	43	56%
May-10	60	42	59%
Jun-10	59	53	53%
Jul-10	61	40	60%
Aug-10	78	30	72%
Sep-10	60	37	62%
Oct-10	72	51	59%
Nov-10	84	18	82%
Dec-10	79	18	81%
Jan-11	52	14	79%
Feb-11	81	9	90%
Mar-11	159	7	96%



Garfield

Date	Closed Loop	Standard	% Closed Loop
Jan-10	7	0	100%
Feb-10	8	2	80%
Mar-10	19	2	90%
Apr-10	13	8	62%
May-10	13	3	81%
Jun-10	13	3	81%
Jul-10	11	1	92%
Aug-10	14	1	93%
Sep-10	15	2	88%
Oct-10	11	4	73%
Nov-10	11	1	92%
Dec-10	13	0	100%
Jan-11	14	3	82%
Feb-11	11	1	92%
Mar-11	18	1	95%



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The documentary *Gasland* has attracted wide attention. Among other things, it alleges that the hydraulic fracturing of oil and gas wells has contaminated nearby water wells with methane in a number of states including Colorado. Because an informed public debate on hydraulic fracturing depends on accurate information, the Colorado Oil and Gas Conservation Commission (COGCC) would like to correct several errors in the film's portrayal of the Colorado incidents.

Background

Methane is a natural hydrocarbon gas that is flammable and explosive in certain concentrations. It is produced either by bacteria or by geologic processes involving heat and pressure. Biogenic methane is created by the decomposition of organic material through fermentation, as is commonly seen in wetlands, or by the chemical reduction of carbon dioxide. It is found in some shallow, water-bearing geologic formations, into which water wells are sometimes completed. Thermogenic methane is created by the thermal decomposition of buried organic material. It is found in rocks buried deeper within the earth and is produced by drilling an oil and gas well and hydraulically fracturing the rocks that contain the gas. In Colorado, thermogenic methane is generally associated with oil and gas development, while biogenic methane is not.

The analytical methods use to differentiate between the two types of methane are well-known, scientifically accepted, and summarized in a well-known presentation by Dennis Coleman and papers by I.R. Kaplan and Dennis Coleman. These works, in turn, cites nearly 75 other references related to the topics of methane generation, "fingerprinting," forensic investigations, and stable isotope geochemistry.

Based upon our review of hundreds of Colorado gas samples over many years, the COGCC is able to differentiate between biogenic and thermogenic methane using both stable isotope analysis of the methane and compositional analysis of the gas. In the Denver-Julesburg and Piceance Basins, the COGCC has consistently found that biogenic gas contains only methane and a very small amount of ethane, while thermogenic gas contains not just methane and ethane but also heavier hydrocarbons such as propane, butane, pentane, and hexanes.
As explained below, *Gasland* incorrectly attributes several cases of water well contamination in Colorado to oil and gas development when our investigations determined that the wells in question contained biogenic methane that is not attributable to such development.

The Weld County Wells

Gasland features three Weld County landowners, Mike Markham, Renee McClure, and Aimee Ellsworth, whose water wells were allegedly contaminated by oil and gas development. The COGCC investigated complaints from all three landowners in 2008 and 2009, and we issued written reports summarizing our findings on each. We concluded that Aimee Ellsworth's well contained a mixture of biogenic and thermogenic methane that was in part attributable to oil and gas development, and Mrs. Ellsworth and an operator reached a settlement in that case.

DEPARTMENT OF NATURAL RESOURCES: Mike King, Executive Director
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However, using the same investigative techniques, we concluded that Mike Markham's and Renee McClure's wells contained biogenic gas that was not related to oil and gas activity. Unfortunately, *Gasland* does not mention our McClure finding and dismisses our Markham finding out of hand.

The Markham and McClure water wells are both located in the Denver-Julesburg Basin in Weld County. They and other water wells in this area draw water from the Laramie-Fox Hills Aquifer, which is composed of interbedded sandstones, shales, and coals. Indeed, the water well completion report for Mr. Markham's well shows that it penetrated at least four different coal beds. The occurrence of methane in the coals of the Laramie Formation has been well documented in numerous publications by the Colorado Geological Survey, the United States Geological Survey, and the Rocky Mountain Association of Geologists dating back more than 30 years. For example, a 1976 publication by the Colorado Division of Water Resources states that the aquifer contains "troublesome amounts of . . . methane." A 1983 publication by the United States Geological Survey similarly states that "[m]ethane-rich gas commonly occurs in ground water in the Denver Basin, southern Weld County, Colorado." And a 2001 report by the Colorado Geological Survey discusses the methane potential of this formation and cites approximately 30 publications on this subject.

Laboratory analysis confirmed that the Markham and McClure wells contained biogenic methane typical of gas that is naturally found in the coals of the Laramie–Fox Hills Aquifer. This determination was based on a stable isotope analysis, which effectively "finger-printed" the gas as biogenic, as well as a gas composition analysis, which indicated that heavier hydrocarbons associated with thermogenic gas were absent. In addition, water samples from the wells were analyzed for benzene, toluene, ethylbenzene, and xylenes (BTEX), which are constituents of the hydrocarbons produced by oil and gas wells in the area. The absence of any BTEX compounds in these water samples provided additional evidence that oil and gas activity did not contaminate the Markham and McClure wells.

The COGCC has also reviewed the records for all oil and gas wells located within one-half mile of the Markham and McClure wells, which is more than double the typical hydraulic fracture length in Colorado. This review indicated that: all oil and gas wells near the Markham well were drilled and hydraulically fractured in 1991, except for two wells that were fractured in 2005 and 2006, respectively; and all oil and gas wells near the McClure well were drilled and hydraulically fractured in 2002, except for one well that was hydraulically fractured in 2005. The records do not reflect any pressure failures or other problems associated with these wells that would indicate a loss of fracture fluid or gas from the well bore into the surrounding geologic formations.

In support of its thesis that the Markham and McClure water wells were contaminated by oil and gas development, the *Gasland* website makes several arguments that merit a brief response. First, the website quotes Professor Anthony Ingraffea of Cornell University for the proposition that drilling and hydraulic fracturing could cause biogenic methane to migrate into aquifers under certain circumstances. However, Professor Ingraffea's statement does not suggest that these circumstances apply to the Markham and McClure wells, nor does it address the extensive scientific literature establishing that biogenic methane is naturally present in the aquifer in question. Second, the website quotes Weston Wilson, an Environmental Protection Agency employee, speculating that oil and gas operators in Weld County are withdrawing large amounts of groundwater and that these withdrawals are releasing biogenic methane. However, oil and gas companies in Weld County obtain most of their water from municipalities, which obtain such water from surface water sources such as the Colorado-Big Thompson and Windy

Gap projects. Finally, the website asserts that the water in the Markham and McClure wells deteriorated after drilling and hydraulic fracturing occurred nearby. However, COGCC records indicate little or no temporal relationship between the Markham and McClure complaints and nearby drilling and hydraulic fracturing activities, which occurred several years earlier and in most cases many years earlier.

The West Divide Creek Seeps

Gasland also addresses complaints about oil and gas activity in the West Divide Creek area of the Piceance Basin in Garfield County, though it again confuses issues related to biogenic gas with those related to thermogenic gas. The film focuses on two seeps that are in close geographic proximity but derive from different origins. One of the seeps occurs in a wetland on property owned by Lisa Bracken, who appears in the film; it contains biogenic methane. The other seep, which the COGCC terms the West Divide Creek gas seep, is about 1,500 feet to the south on property owned by a neighbor; it contains thermogenic methane caused by EnCana's failure to properly cement a natural gas well.

Gasland adopts the claim that the West Divide Creek gas seep was caused by hydraulic fracturing. After investigating the matter thoroughly in 2004, COGCC staff concluded the seep was caused by gas migrating up a gas well borehole that had not been properly cemented and in which the upper portion of the gas bearing Williams Fork Formation had not been isolated. On August 16, 2004, following a public hearing, the COGCC commissioners approved an enforcement order (Order 1V-276) that incorporated the staff's causation conclusions and assessed a substantial fine against the operator.

In investigating the West Divide gas seep, the COGCC determined that it contains thermogenic methane. The gas composition and stable isotope signature of the gas closely matched that of the gas being produced from the Williams Fork Formation. The gas from both the West Divide Creek seep and the Williams Fork Formation is composed primarily of methane, but it also contains ethane, propane, butane, pentane, and hexanes. In addition, BTEX compounds were detected in ground and surface water in the vicinity of the West Divide Creek seep, which indicates that the gas is related to oil and gas activities and not of biogenic origin.

In contrast, the laboratory results for the gas samples collected from the seep on Ms. Bracken's property have demonstrated that the gas is biogenic. The COGCC has collected nine gas samples on six different occasions during 2004, 2007, 2009, and 2010. With respect to each sample, the gas composition was found to be 100 percent methane, no heavier hydrocarbon compound was detected, and the stable isotope ratio indicated that the gas is biogenic. The COGCC has also collected six water samples on four different occasions during 2004, 2007, and 2009 and ten soil samples on multiple occasions during 2008 and 2009 from Ms. Bracken's property. BTEX compounds and/or other hydrocarbons associated with oil and gas operations were not detected in any of these samples. Based on these results, the COGCC has concluded that the gas seep on Ms. Bracken's property resulted from the fermentation of organic matter by methanogenic bacteria. This is not uncommon in wetland areas, such as those that exist along West Divide Creek.

Other Information

Oil and gas development is an industrial activity, and property owners sometimes complain that it has contaminated their water well. The COGCC investigates all such complaints and reports the results individually to the complainant and collectively to the Colorado Water Quality Control

Division. In some cases, the COGCC has found that the well contains thermogenic methane linked to oil and gas development. In most cases, however, the COGCC has found that contamination is not present or that the methane comes from biogenic sources and is not attributable to oil and gas production. The following excerpt from a report summarizing the COGCC's investigation following the contamination of the Ellsworth water well is illustrative:

> In response to concerns regarding the presence of methane gas in water wells completed in the Laramie/Fox Hills Aquifer, COGCC, Noble Energy, and Anadarko/Kerr McGee sampled a total of 28 water wells between March 25, 2009 and April 7, 2009 across an approximately 170 square mile area. Sample results show that these wells contained either no methane gas or biogenic (biological generated) methane gas. None of these wells, other than the Ellsworth water well, contained thermogenic methane gas. The sample results along with letters discussing the results were sent by COGCC staff to the 28 well owners [who had requested testing].

Nevertheless, it remains important to establish prudent regulations to ensure that other resources, such as groundwater, are protected. Producing oil and gas formations in much of Colorado, including the Denver-Julesburg and Piceance Basins, lie at depths of up to 8,000 feet below the ground surface, while the aquifers that sustain domestic water wells are generally less than 1,000 feet below the ground surface. COGCC regulations establish casing and cementing standards to ensure that gas being produced from 8,000 feet down does not leak into the shallower aquifers. These regulations require wells to be cased with steel pipe and the casing to be surrounded by cement to create a hydraulic seal within the annular space between the wall of the well bore and the steel pipe. In addition, a number of recent amendments to the COGCC regulations address concerns raised about hydraulic fracturing:

- Rule 205 requires operators to inventory chemicals, including fracturing fluids, and to provide this information upon request to the COGCC and certain health care professionals;
- Rule 317 requires cement bond logs to confirm that aquifers are protected;
- Rule 317B imposes mandatory setbacks and enhanced environmental precautions on oil and gas development occurring near public drinking water sources;
- Rule 341 requires well pressures to be monitored during hydraulic fracturing;
- Rule 608 mandates additional pressure testing and water well sampling for coalbed methane wells; and
- Rules 903 , 904 , and 906 impose enhanced requirements for pit permitting, lining, monitoring, and secondary containment to ensure that pit fluids, including hydraulic fracturing flowback, do not leak

Finally, it should be understood that the COGCC Director, Dave Neslin, offered to speak with *Gasland's* producer, Josh Fox, on camera during the filming of the movie. Because the issues are technical and complex and arouse concerns in many people, Director Neslin asked that he be allowed to review any material from the interview that would be included in the final film. Unfortunately, Mr. Fox declined. Such a discussion might have prevented the inaccuracies noted above.

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OIL & GAS
CONSERVATION COMMISSION

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August 7, 2009

Mr. and Mrs. Ellsworth
20991 Weld Count Road 20
Fort Lupton, CO 80621

RE: Ellsworth Water Well Investigation (WW Permit No. 201558)
SESE Section 16 – Township 2 North - Range 65 West
COGCC Complaint Investigation No. 200196553
Weld County, Colorado

Dear Mr. and Mrs. Ellsworth:

This letter summarizes the process, results, and conclusions of the Colorado Oil and Gas Conservation Commission (COGCC) staff investigation into the occurrence of hydrocarbon gases in your water well under COGCC Complaint Investigation No. 200196553.

The Division of Water Resources (DWR) permit number for your water well is No. 201558 and according to the DWR water well record it was drilled in October 1998 to a total depth of 695 feet below the ground surface (fbgs) and completed as a Laramie-Fox Hills Aquifer water well. The well is screened from 475 to 685 fbgs. The well was drilled under a permit issued to Ronald Lakey of Longmont, Colorado. In 2001, the Dickhausens of Thornton, Colorado submitted to DWR a Pump Installation and Test Report for this water well. The test report shows the installation of a submersible water pump with an intake at a depth of 500 fbgs and a pumping rate of 15 gallon per minute.

On or around September 18, 2008, Mrs. Ellsworth contacted COGCC staff for assistance in investigating the occurrence of methane gas in your water well. You indicated that you had recently purchased the property and water well at 20991 WCR 2, and that when the water well was pumped you noticed significant bubbling in the water and when the water treatment system was "back-washed" into the septic tank the septic pump shut off automatically. On your behalf, a third party contractor had collected and analyzed samples of the gas collected from the house kitchen sink and determined that the gas was methane. Because there are active oil and gas production wells and facilities in the area in which you live, you were concerned that the methane gas in your water well might be related to a release from one of these facilities/wells.

On August 10, 2008, you had also collected samples from the water well and submitted these samples to Weld County Department of Public Health and Environment (WCDPHE) for analysis. Methane was not one of the constituents analyzed by the WCDPHE. You have provided the COGCC staff with the analytical results from that sampling.

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COGCC STAFF: David Neslin, Director – Debbie Baldwin, Environmental Manager – David K. Dillon, Engineering Manager

In response to your complaint, on September 22, 2008, COGCC staff collected samples from your water well for analysis of general water quality parameters, organic compounds associated with oil and gas production, gas composition and stable isotopes of methane and deuterium, and for nuisance bacteria. Upon receipt of the analytical results the COGCC staff sent you a summary letter on October 27, 2008, presenting and discussing the results from the COGCC sampling. In addition, the COGCC letter compared the results with those from the WCDPHE analyses. The methane gas present in the September 22, 2009, COGCC sample was identified as being a mixture of thermogenic and biogenic gas and the heavier hydrocarbon gases were thermogenic. The thermogenic gases are likely related to oil and gas operations.

As a result of the determination that the gas in your water well was in part thermogenic, the COGCC staff began an investigation of the producing oil and gas wells in the vicinity of your water well for evidence of a release of production gas into the Laramie-Fox Hills Aquifer. The operators of these wells are Noble Energy (Noble) and Kerr McGee/Anadarko (KMG). COGCC staff contacted Noble and KMG to inform them that a water well impacted by thermogenic gas had been discovered and that the COGCC would be investigating the source of the gas.

From the date of your original contact with the COGCC, the staff has devoted significant resources to try to determine the source of the thermogenic hydrocarbon gases in your water well. Six staff members have been involved to varying degrees in this effort. As is the COGCC's standard procedure, you have been kept informed about all phases of the investigation. When available, analytical results and a discussion of the COGCC's interpretation of the results have been sent to you. The COGCC staff has answered numerous inquiries from you totaling approximately 40 separate email and telephone communications. In addition, staff has prepared approximately 20 written communications for you explaining the steps being taken in our investigation. The following is a summary of our investigation activities and conclusions.

ENGNEERING AND WATER WELL INVESTIGATION

Engineering Investigation – Oil and Gas Wells

Concurrent with evaluation of your water well sample results, the COGCC Engineering staff initiated review of drilling, well construction, and well completion records for the 37 oil and gas wells within a one-mile radius of your water well. The review included checking the surface casing depth, checking whether the Laramie-Fox Hills Aquifer was protected by the well construction, and checking whether there were anomalies in gas production that might indicate gas leakage from the well.

Based on COGCC staff experience investigating impacts to ground water, we focused the field testing of oil and gas wells to those within ½ mile of your water well. This is because, except in very rare instances, oil and gas wells that have impacted water wells are located less than 1,000 feet from the impacted water well, so our process of field testing oil and gas wells located up to ½ mile or 2,640 feet from an impacted water well extends by more than 2½ times this distance. In addition, thermogenic gas or a mixture of thermogenic and biogenic gas was not detected in any other water wells so we conclude that the impact to the Laramie-Fox Hills Aquifer that is affecting your well is localized.

There are nine oil and gas wells within ½ mile of your water well. On October 15, 2008, COGCC staff witnessed measurement of bradenhead pressures on these nine wells. The bradenhead valve is connected to the open space between the production casing and the surface casing and opening the valve to measure pressure and check for gas and fluids is a technique used to help determine whether there is a casing or wellhead leak. Bradenhead pressures were not measured and fluids were not present in any of the nine wells tested.

On January 8, 2009, Noble performed a mechanical integrity test (MIT) on the Powers 21-22 well which had been selected by the COGCC staff for further investigation based on some earlier well casing/well cementing issues. The MIT involves pressuring-up the production casing of an oil and gas well and observing any pressure loss which would indicate a possible production casing leak. This well passed the MIT. In March 2009, the remaining wells within the ½ mile radius were MITed. All these wells passed the MITs.

The results of the bradenhead pressure measurements and MITs indicate that the oil and gas wells within ½ mile of your water well are operating properly and not leaking gas, but do not negate the possibility of a prior leak that was subsequently remediated.

Former Powers No. 1 well

Staff review of COGCC well files showed that an old well, the Powers No. 1 (API 05-123-05076), had been drilled sometime around 1946 in Section 22, Township 2 North, Range 65 West, which is southeast of your property. However, the COGCC records regarding the Powers No. 1 did not specify the exact well location or include information about the depth, casing, or how the well was abandoned. Because of the limited amount of information in the COGCC records and because this old well had the potential to be a source or conduit for ground water contamination, the COGCC conducted a search for additional information about this well. Records concerning the Powers No. 1 well were found at the Denver Earth Resources Library, which provided a specific location and information about both well casing and depth. According to the records, the Powers No. 1 well was spud on April 18, 1946 by J. Clayton and drilled to a total depth of 1,005 fbgs with well casing set to a depth of 335 fbgs. Other than some information about the rocks encountered during the drilling of the well (i.e., lithologic information), no additional information was found.

Between May 26, 2009, and June 16, 2009, the COGCC reentered the old well bore, sampled the well for gas and general water quality, and abandoned the well by cementing the borehole from total depth to the surface. Results of a sample collected on May 27, 2009, show that the former Powers No. 1 did not have gas in it and there were no unusual water quality results observed. A second sample collected on June 11, 2009, was analyzed for gas composition and stable isotopes of carbon and hydrogen. A small amount of biogenic methane gas, similar to the biogenic gas that occurs frequently in the Laramie-Fox Hills aquifer, was detected.

As a result of the reentry and sampling, the COGCC staff determined that the Powers No. 1 well is not the source of the thermogenic gas observed in your water well. The COGCC spent approximately $107,000 on reentering and properly plugging this well.

Water Well Investigation

On February 20, 2009, COGCC staff collected a second sample of gas from your water well and on March 11, 2009, a second water sample was collected. The analytical results for these two samples are similar to the results for the water and gas samples collected by staff on September 22, 2008.

Between October 22, 2008, and April 7, 2009, COGCC staff collected production gas samples from the nine oil and gas wells within ½ mile of your water well for gas composition and stable isotope analysis. As part of the COGCC staff evaluation of the theromgenic gas in your water well, the analytical results of these production gas samples were compared to the analytical results for the gas from your water well. Unfortunately, after a thorough review of all of the analytical results the COGCC staff is unable to identify any of the oil and gas wells within ½ mile of your water well as the source of the thermogenic hydrocarbon gases (methane, ethane, propane, iso- and n-butanes, iso- and n-pentanes, and hexanes) present in your well.

Throughout large areas of Weld County the Laramie-Fox Hills Aquifer, in which your water well is completed, has naturally occurring bacterially produced methane (biogenic methane). The source of this natural methane is likely from coals present in the aquifer. Isotopically and compositionally, this biogenic gas has a distinctive signature that is different from the composition of the thermogenic gas and the stable isotopes of the methane produced from the oil and gas wells in your area. Generally, these differences make identifying the presence of thermogenic gas in a water well versus naturally occurring biogenic gas relatively straight forward. However, when the gas in a water well is a mixture of biogenic and thermogenic gas the isotopic signature of the gas is not as definitive a tool for determining the source. When this occurs, the evaluation of the other hydrocarbon gases, propane, iso- and n-butanes, iso- and n-pentanes, and hexanes (C3 through C6), which are present in the production gas, is very important and often helps in identifying a possible source. The biogenic gas in the Laramie-Fox Hills Aquifer does not contain C3 through C6 gases and, when present in a Laramie-Fox Hills Aquifer water well, it is evidence of an impact from thermogenic gas (as was noted in the October 2008 evaluation of your water well).

Comparison of the C3 through C6 compounds from an impacted water well to those in the gas produced from oil and gas wells in the area is a tool used by the COGCC staff to identify a possible source. The COGCC staff looked at both the isotopes of methane and the occurrences of the other hydrocarbon gases in the samples collected both from your water well and the oil and gas wells. The methane gas in your water well is a mixture of both naturally occurring biogenic gas and thermogenic gas which, as discussed earlier, makes the identification of a specific source difficult. Based on isotopic evaluation of the methane in your water well and the samples from the production wells, the COGCC staff are unable to identify a particular oil and gas well as the source of thermogenic gas in your water well. Our evaluation of the C3 through

C6 compounds from the production well samples and your water well also failed to positively identify a particular oil and gas well as the source.

Other Water Well Sampling

As part of the investigation into the occurrence of methane gas in your water well and to determine whether other water wells had been impacted, 26 water wells were sampled. This sampling and analysis was conducted by the COGCC, Noble, and KMG. Thermogenic gas was not detected in any of these other water wells. Because the results of this sampling and analysis have been discussed in earlier communication and correspondence with you, they will not be discussed in this letter. The COGCC spent approximately $30,000 collecting and analyzing samples from water wells and oil and gas wells.

You have expressed concern that some of the samples collected from water wells were collected at a time when nearby oil and gas wells had been "killed." You have further stated that the "killing" of these wells rendered the analytical results invalid because it had effectively cut off gas that was leaking out of a well or wells. However, it is COGCC's experience that if an oil and gas well has leaked and impacted ground water the effects of that leak can be detected long after the leak has been repaired or the well has been plugged and abandoned; therefore, we believe that if another water well had been impacted by gas leaking from an oil and gas well the thermogenic gas that would have been entrained in the ground water would still be present and would have been detected in the water sample. That being said, if any of your neighbors still believe that their water well contains thermogenic gas or has been impacted by gas leaking from an oil and gas well they should contact us and we will collect additional samples from their water well for laboratory analysis.

Mitigation of the Gas in Your Water Well

On March 21, 2009, Noble voluntarily began providing you with temporary substitute water for domestic use at your home. By letter dated June 17, 2009, you and Noble jointly advised me that you had recently agreed upon certain measures to further mitigate the natural gas detected in your water well. That letter states that Noble will install a filtration system to remove the gas from your water well and make such well safe for your use. The letter also states that you and Noble have further agreed to cooperate and work diligently to resolve any remaining issues between you. It is our understanding that the filtration system is designed to mitigate the methane and other gases entrained in your water and eliminate possible fire or explosion hazards and is now operating.

CONCLUSION

The method used by the COGCC staff to investigate and address the impact to your water well has been thorough and appropriate. The COGCC staff's conclusion, supported by all the investigation records, is that your water well contains a mixture of both biogenic and thermogenic gas and that the thermogenic gas appears to be from oil and gas activity; however, the COGCC staff has been unable to identify any current activity or existing well as the source of the impact. As previously discussed, all current oil and gas wells within ½ mile of your water well are operating properly and not leaking gas, but this does not negate the possibility of a prior leak that was subsequently remediated. Based on our experience investigating other groundwater impacts, as well as our review of oil and gas well records and water well samples, we do not believe that the gas in your water well is attributable to an oil and gas well located more than ½ mile away.

Because no responsible party for the water well impact can be identified, the staff will not be issuing a notice of violation (NOAV) or pursuing enforcement against any oil and gas operator as a result of the investigation of Complaint No. 200196553. Because Noble voluntarily has constructed a water treatment system to mitigate the gas in your well water and because all oil and gas wells within ½ mile of your water well are operating properly, the COGCC staff considers the situation mitigated and COGCC complaint No. 200196553 closed. Nonetheless, if you wish, the COGCC staff will continue to collect samples from your water well for gas composition and stable isotope analysis on an annual basis. In the event that such analysis or any other future information allows us to identify the party responsible for the thermogenic gas in your water well, then we may issue an NOAV or pursue enforcement at that time.

Under COGCC Rule 522, you as the complainant, have the right to file an application for a hearing with the Commission regarding this complaint if you are not satisfied with this resolution. If you wish to apply for a hearing, please contact Rob Willis, COGCC Hearings Officer at 303-894-2100 ext. 5125.

If you have any questions or would like to discuss these matters further, please contact me at 303-894-2100 ext. 5122, or Debbie Baldwin, COGCC Environmental Manager at ext. 5111, or Dave Dillon, COGCC Engineering Manager at ext. 5104.

Respectfully,

David S. Neslin

David Neslin
Director
Colorado Oil & Gas Conservation Commission

cc: Weld County Commissioners

Exhibit B

Statement of Basis, Specific Statutory Authority, and Purpose

New Rules and Amendments to Current Rules of the Colorado Oil and Gas Conservation Commission, 2 CCR 404-1

This statement sets forth the basis, specific statutory authority, and purpose for new rules and amendments to the Rules and Regulations and Rules of Practice and Procedure ("Rules") promulgated by the Colorado Oil and Gas Conservation Commission ("COGCC") on December 11, 2008. These rules are promulgated to protect public health, safety, and welfare, including the environment and wildlife resources, from the impacts resulting from the dramatic increase in oil and gas development in Colorado. They also implement new statutory authority and update existing regulations where appropriate. They are intended to foster the responsible and balanced development of oil and gas resources.

Unless otherwise specified, the new rules and amendments become effective on May 1, 2009 on federal land and April 1, 2009 on all other land.

In adopting the new rules and amendments, the Commission relied upon the entire administrative record for this rulemaking proceeding, which formally began in March 2008 and informally began in the summer of 2007. This record includes the proposed rules and numerous recommended modifications and alternatives; thousands of pages of public comment, written testimony, and exhibits; and 12 days of public and party hearings. The Commission spent another 12 days deliberating on the rules before taking final action.

Statutory Authority

The additions and amendments to the rules are promulgated pursuant to the authority granted to COGCC by House Bills ("HB") 07-1298 and 07-1341, codified at sections 34-60-106 and 34-60-128, C.R.S., of the Oil and Gas Conservation Act ("Act"). Additional authority for the promulgation of the rules is provided by sections 34-60-102, 34-60-103, 34-60-104, 34-60-105, and 34-60-108, C.R.S. of the Act. The Commission also adopted the following statement of basis and purpose consistent with section 24-4-103(4), C.R.S., of the Administrative Procedure Act. This statement is hereby incorporated by reference in the rules adopted.

The rulemaking hearing for these rules was held on May 22, 2008 (initial motions); June 10, 2008 (public testimony); June 23-27, 2008 (public and party testimony); June 30-July 1, 2008 (party testimony); July 15-17, 2008 (party testimony); August 19-20, 2008 (deliberations); September 9-11, 2008 (deliberations); September 22-23, 2008 (deliberations); October 26-27, 2008 (deliberations); and December 9-11, 2008 (deliberations).

Purpose

Address Growing Impacts of Increase in Oil and Gas Activity

A major reason for adopting these regulations was to address concerns created by the unprecedented increase in the permitting and production of oil and gas in Colorado in the past few years. In 1996, the COGCC, through its Director, approved 1,002 applications for permits to drill ("APD"). In 2004, that number increased to 2,915 approved APDs. In 2007, the COGCC approved 6,368 APDs. The COGCC anticipates that it will approve approximately 7,500 APDs in 2008. This increase in permitting levels generally corresponds to an increase in drilling activity, particularly in the Piceance Basin, where drilling has extended into new areas with more extensive wildlife and water resources, more challenging terrain, and additional people. These increases require the COGCC to re-evaluate its regulatory scheme to ensure that its rules are appropriate for the heightened level and broader geographic extent of development activity in Colorado. In addition, as the level and extent of drilling activity has increased, so has the public concern for the health, safety and welfare of Colorado's residents. The level of public concern for Colorado's environment and wildlife resources has also risen with the increase in permitting and drilling over the past few years. With the number of approved APDs increasing by approximately 750% in twelve years (and 257% in just four years) and the public concerns engendered by the increased activity, the COGCC's re-evaluation was necessary and appropriate.

Implement 2007 Legislation

In 2007, upon the urging and initiative of the Colorado Department of Natural Resources, the General Assembly passed legislation to increase the Commission's regulatory authority and oversight obligations to better address the potential adverse impacts that can accompany oil and gas development. The General Assembly declared that it is in the public's interest to foster the *responsible, balanced* development of Colorado's oil and gas resources consistent with the protection of public health, safety, and welfare, *including protection of the environment and wildlife resources*. C.R.S. § 34-60-102(1) (emphasis added).

The new rules comply with the legislative mandate to: (1) foster oil and gas development consistent with the protection of public health, safety, and welfare, including the environment and wildlife resources; (2) promote the conservation of wildlife habitat in connection with the development of oil and gas; and (3) minimize adverse impacts to wildlife resources affected by oil and gas operations and ensure proper reclamation of wildlife habitat. C.R.S. § § 34-60-106, 34-60-128.

In order to protect the health, safety, and welfare of the general public, the COGCC staff developed the rules in consultation with the Colorado Department of Public Health and Environment ("CDPHE"). C.R.S. § 34-60-106(11)(a)(II). As directed by the legislature, the rules provide a timely and efficient procedure by which the CDPHE has an opportunity to provide comments during the COGCC's decision-making process. *Id.*

In order to minimize adverse impacts to wildlife resources and ensure proper reclamation of wildlife habitat, the COGCC staff developed the rules in consultation with the Colorado Division of Wildlife ("CDOW"). C.R.S. § 34-60-128(3)(d)(I). As directed by the legislature, the rules: (1) develop a timely and efficient consultation process with the CDOW governing notification and consultation to minimize adverse impacts and other issues relating to wildlife resources; (2) encourage operators to utilize comprehensive drilling plans and geographic area analysis strategies to provide for orderly development of oil and gas fields; and (3) minimize surface disturbance and fragmentation in important wildlife habitat by incorporating appropriate best management practices in certain COGCC orders and decisions. *See* C.R.S. § 34-60-128(d)(I-III).

Update Existing Rules Where Appropriate

The COGCC staff also identified existing rules to update in order to enhance clarity, respond to new information, and reflect current practice and procedure. Although the Commission has annually adopted or amended particular rules, the last set of comprehensive amendments occurred more than a decade ago and various rules had become outdated. For example, before amendment some of the environmental and financial assurance rules no longer adequately addressed current needs and conditions. Similarly, before amendment some of the procedural rules did not reflect current COGCC practices. Therefore, the Commission used this as an opportunity to update existing rules where appropriate.

Background

Development of the Draft Rules

The General Assembly entrusted the Commission with the weighty task of fine-tuning the balancing act between the development of the oil and gas resources and the protection of public health, safety, and welfare, including the environment and wildlife resources. The COGCC staff therefore began the development of the draft rules with the understanding that the continuation of oil and gas development is important to Colorado, as is the protection of Colorado's citizens and environment from the negative impacts of such development.

In the summer of 2007, staff members of the COGCC, CDPHE, and CDOW met and began identifying specific areas where new COGCC regulations were required to properly address identified problems and implement HBs 07-1298 and 07-1341. In addition, the staff members of the three agencies began contacting individuals who participated in drafting HBs 07-1298 and 07-1341 and other people that either expressed an interest in or were believed to potentially be affected by the proposed rulemaking, including representatives from the oil and gas industry, the environmental community, local governments, federal agencies, sportsmen, and property owners.

In November 2007, the COGCC staff circulated a document entitled "Initial pre-draft rulemaking proposal to implement HBs 07-1298 and 07-1341" ("pre-draft proposal") to stakeholders. The COGCC also posted this document on its website. The pre-draft proposal was a conceptual, narrative document, which was intended to frame the issues and facilitate public input prior to development of the draft rules. Once the pre-draft proposal was distributed, all stakeholders and members of the public were given the opportunity to review and comment on the document, and thousands of pages of such comments were received by the COGCC staff. Once the public comment began in December 2007, all public comment pertaining to the rulemaking was posted on the COGCC website as time and resources allowed.

To obtain additional public comment prior to development of the draft rules, the COGCC, CDPHE, and CDOW staffs held five meetings in January 2008 in communities significantly affected by oil and gas development. These meetings were held in Parachute, Greeley, Wray, Durango, and Trinidad, and they were collectively attended by approximately 1,700 people. They provided the staffs with substantial additional input on the pre-draft proposal and rulemaking and apprised the public of the rulemaking process.

Also during January and February 2008, the COGCC staff convened nine technical work groups to discuss some 67 issues associated with the pre-draft proposal. These work groups held a total of 37 meetings, which lasted about 150 hours, and were attended by about 250 stakeholders. Through these meetings, the participants shared their perspectives on a range of issues associated with the pre-draft proposal and the rulemaking, including existing problems, regulatory costs and benefits, efficiency and timing concerns, and alternative approaches. All of these meetings were noticed on the COGCC website, and were open to interested members of the public.

Through the initial meetings, pre-draft proposal, public meetings, and technical work groups, the COGCC staff received broad stakeholder and public input before the draft rules were prepared and the formal rulemaking process began. Local governments, oil and gas companies, environmental groups, sportsmen, and other members of the public received and took advantage of numerous opportunities to offer input regarding the development of the draft rules.

After careful consideration of this input, the COGCC staff in consultation with the CDPHE and CDOW drafted proposed rules which were provided to the Commission and posted on the COGCC website on March 31, 2008 and published in the Colorado Register on April 10, 2008. The draft rules differed substantially from the pre-draft proposal. Of 21 topics addressed in the draft rules, 17 of them reflected significant changes from the pre-draft proposal. Changes were made to simplify requirements, better differentiate between different geologic basins, further minimize adverse impacts to public health, the environment, and wildlife resources, and ensure timely and efficient action. These changes improved the draft rules and better balanced the development of oil and gas with the protection of public health, safety and welfare, including the environment and wildlife resources.

Rulemaking Hearing and Development of the Final Rules

The COGCC staff submitted its prehearing statement in support of the draft rules on April 18, 2008, which included extensive written testimony and exhibits from COGCC, CDPHE, and CDOW staff. This testimony described the problem each draft rule was designed to address, explained how each proposed change would address the problem and result in greater protection for public health or the environment, and evaluated whether the proposed rule would affect industry's ability to develop the resource efficiently and whether it would effectively balance development of oil and gas resources with protection of public health, safety, and welfare, including the environment and wildlife resources.

Eighty-five different individuals or organizations requested party status to this rulemaking, including government organizations, oil and gas companies, conservation groups, and agricultural associations. These parties filed responsive prehearing statements in May 2008. Their responses included thousands of pages of additional written testimony and exhibits. In addition to filing responsive prehearing statements, these parties to the rulemaking were given numerous opportunities to present witnesses and written materials to the Commission throughout the rulemaking hearing, as described below.

On May 16, 2008, the COGCC staff, in consultation with the CDPHE and CDOW, submitted a cost-benefit and regulatory analysis, to provide additional information to the Commission, parties, and public, and to comply with the Administrative Procedure Act, C.R.S. § 24-4-101 *et. seq*. This 182-page analysis addressed each of the proposed rules and described, *inter alia*, the likely beneficiaries of the proposed rule and the nature of any anticipated benefit, the likely costs expected to be incurred as a consequence of the proposed rule, and any adverse effects of the proposed rule on small businesses or consumers. For each proposed rule, the cost-benefit and regulatory analysis compared the overall benefits and costs of the proposed rule to alternative approaches and explained why the alternative approaches had been rejected.

The Commission commenced the rulemaking hearing on May 22, 2008 in Denver, reviewing a prehearing order and considering appeals from any party regarding procedural decisions contained therein. The Commission also addressed initial motions filed by the parties, including motions seeking to bifurcate or limit the proceeding. Both staff and parties to the rulemaking subsequently filed rebuttal prehearing statements in early June 2008.

The Commission heard approximately eight hours of public testimony on June 10, 2008 in Grand Junction, Colorado and approximately four hours of public testimony on June 23, 2008 in Denver, Colorado. The Commission began hearing testimony from parties and party witnesses on June 23, 2008 in Denver. For the next six days, the Commission heard testimony from parties or party witnesses, cross-examination by parties, and answers to Commissioner questions from parties or party witnesses. The Commission reconvened for three more days of testimony, cross-examination, and questioning during July 15-18, 2008 in Denver.

Throughout this period, the COGCC staff was in frequent discussion with parties regarding the draft rules. Based upon these discussions and its own further evaluation, the COGCC staff issued clarifications to several of the proposed rules in May and June 2008. In consideration of arguments and alternative proposals contained in the parties' responsive prehearing statements and rebuttal statements, the COGCC staff issued a comprehensive set of suggested revisions to the proposed rules on June 18, 2008. The Commission invited groups of parties to submit alternative language for the proposed rules by July 30, 2008. Each of the party groups submitted alternative language, and some party groups submitted additional material in support of their proposed alternative approaches. The COGCC staff reviewed these submittals and, on August 11, 2008, submitted alternative recommended language for several of the draft rules.

The Commission closed the evidentiary record and commenced deliberations on August 19-20, 2008 in Denver on those rules for which the COGCC staff had developed alternative recommended language. During these deliberations, the Commission initially approved each of these rules, subject to changes provisionally approved in the deliberations. During these two days of deliberations, the Commission gave initial approval to fifty of the proposed rules.

The COGCC staff then reviewed the parties' July 30, 2008 submittals for the balance of the proposed rules and, on September 3-5, 2008, submitted recommended alternative language for each of the remaining draft rules. The Commission conducted deliberations on these draft rules on September 9-11 and 22-23, 2008 and on October 26-27, 2008. During these deliberations, the Commission gave initial approval to the remainder of the proposed rules.

At the conclusion of the initial deliberations, COGCC staff reviewed the transcripts of the proceedings and prepared final rule language. Where the Commission directed the staff to prepare new language for particular rules, the staff gave the parties an opportunity to review and comment to the Director on that new language. On November 7, 2008, the COGCC staff submitted final rule language for the Commission's review and consideration. The Commission conducted final deliberations on this language and adopted the final rules on December 9-11, 2008.

This was the most extensive rulemaking hearing in the Commission's history. All told, the Commission held twenty-two days of hearings, with some the days lasting almost twelve hours. The Commission heard approximately twelve hours of public comment by approximately two hundred people. It heard from approximately one hundred sixty party and staff witnesses and heard approximately seventy-five hours of testimony, cross, examination, and answers to Commissioner questions on twelve days of hearings. The Commission also considered more than thirty legal motions and conducted nine days of initial and final deliberations totaling more than seventy additional hours. Throughout the hearing, the Commission listened to all of the witnesses, questioned aspects of witnesses' written testimony, directed its staff to work with parties, and asked clarifying questions as necessary. The Commission repeatedly extended the rulemaking hearing in order to hear additional testimony and argument and conduct additional deliberations. It also directed and approved numerous changes to the draft rules that reflect input from the parties.

The Commission believes that the resulting final rules responsibly address the recent increase in oil and gas development, implement the 2007 legislation, and update the prior rules where appropriate. It also believes that these rules will ensure the protection of the public health, safety and welfare, including the environment and wildlife resources, while also fostering the responsible, balanced development, production, and utilization of oil and gas resources. C.R.S. § 34-60-102(1)(b). These rules will, among other things:

- Provide additional protection for public health and the environment through several new measures. These measures include requirements that operators maintain an inventory of chemicals kept onsite for use downhole, restrict operations in areas near drinking water sources, install emission control devices on certain equipment located near homes, schools, and other occupied buildings, and implement additional stormwater management measures. *See* Rules 205, 317B, 805, and 1002;

- Minimize adverse impacts on wildlife resources by requiring operators to work with CDOW regarding site-specific mitigation for sensitive wildlife habitat (mostly located in Western Colorado) and to avoid the most critical habitat areas where technically and economically feasible. *See* Rules 1201-1205;

- Provide for consultation with the CDPHE and CDOW in appropriate circumstances. These consultations will result in recommendations to the COGCC Director on appropriate conditions of approval to protect public health, the environment, and wildlife. For wildlife conditions, the Director's decision will be subject to surface owner consent. *See* Rules 306, 1202;

- Provide for timely efficient permitting through measures such as limiting the duration of CDPHE and CDOW consultation and public comment, expediting approvals under certain circumstances, and Commission review if permitting decisions are not timely issued. The rules also omit earlier proposals to develop an expansive new application form and require wildlife surveys. *See* Rules 216, 303, 305, 306, and 1201;

- Encourage landscape level planning through operator-initiated Comprehensive Drilling Plans, which will facilitate early and collaborative review and in certain circumstances aggregate and expedite regulatory approvals. While such Plans will be optional, the rules contain incentives for their use. *See* Rule 216;

- Provide for enhanced transparency by notifying surface owners, the owners of nearby surface property, local governments, the CDPHE and CDOW, and the public of permit applications and providing them with a minimum 20-day period to submit comments to the Director. *See* Rule 305; and

- Avoid a one-size-fits-all approach by tailoring numerous rules to the individual circumstances of the location or region. This includes rules concerning the requirements for compliance checklists, permit applications, notice, drinking water protection, odor control, and wildlife habitat protection. *See* Rules 206, 303, 305, 317B, 318A, 318B, 805, and 1202-1205.

Colorado Oil and Gas Conservation Commission

Cause No. 1V Docket 0408-OV-27

COGCC Staff Presentation
August 16 and 17, 2004

EVIDENCE WHY WEST DIVIDE CREEK GAS SEEP WAS NOT CAUSED BY HYDRAULIC “FRACING”

- BRADENHEAD PRESSURE MONITORING DURING FRAC SHOWED NO COMMUNICATION ABOVE TOP OF CEMENT

- NORMAL FRACTURE TREATMENT PRESSURE SHOWED CONTAINMENT OF FRAC FLUIDS WITHIN THE TARGET ZONE

- NO INDICATION OF FRAC FLUIDS WERE DETECTED IN SEEP AREA SAMPLES

- WEST DIVIDE CREEK GAS SEEP DECREASED AFTER THE REMEDIAL CEMENTING OF THE SCHWARTZ 2-15B WELL. THIS WOULD NOT HAVE OCCURRED IF HYDRAULICALLY INDUCED FRACING CAUSED THE SEEP

Senator CARDIN. Thank you all for your testimony.

I am going to urge the committee Members if they could limit themselves to a 4-minute round so we can get the panel completed before the vote on the floor.

Let me thank all of you for your testimony.

Mr. Cloud, I just really want to compliment the actions taken in your State of Oklahoma. I think you have provided a good model that should be used in other States.

I am very impressed that the back-flow by State action can either be recycled or must be put into, as I understand it, one of the containment wells which operates under the Clean Water Act.

So it seems to me that you have been able to do exactly what Mr. Perciasepe indicated, the Federal Government working with the State to develop the right framework for dealing with natural gas extraction.

Why is it that you prohibit the back-flow from entering into our wastewater treatment facility plants? Why have you taken that action?

Mr. CLOUD. Thank you, Mr. Chairman.

I believe that the State has for many years since we have been doing hydraulic fracturing for 60 years, we have kept a close eye on it. We just make sure that the frack fluids be kept out of the water supplies and they are never sent to water treatment facilities, as you outlined, only to be recycled or to be back-injected into abandoned wells.

Senator CARDIN. I think that is the right way to proceed and I am curious as to why Pennsylvania and other States are still allowing the back-flow to enter treatment facility plants. Do either one of my friends from Pennsylvania have an explanation as to why the State is still permitting that?

Mr. VOLZ. Well, I think I do, Senator. It essentially boiled down to there was a very pressing need to dispose of a lot of material. There were a lot of wells drilled very quickly. I believe it was an oversight by our Pennsylvania Department of Environmental Protection that a lot of this material was going to these brine treatment facilities that are very inefficient, as well as these sewage treatment plants. No one had a real handle on it.

Senator CARDIN. It is my understanding there are wells that it could have been injected to. It may have required some transportation, but there are wells that would have accepted it.

Mr. VOLZ. In Ohio, sir.

Senator CARDIN. Yes, but it was a transportation issue, a cost issue, I assume, so it is pragmatic decision made which is we never want to see public health put at risk due to a pragmatic judgment.

Dr. Summers, as I understand it, the Maryland legislature did not act yesterday on a moratorium, but as I understand what you were saying, at the present time Maryland is uncomfortable in moving forward until you understand the practices that will be used will be safe for public health. Is that true?

Mr. SUMMERS. That is correct. We have just started to receive permits. We have been watching very closely what has been going on in Pennsylvania. We are reviewing the work out of New York, looking at what is going on in other States; are very interested to look more closely at how Wyoming is handling this.

Our plans are to proceed very cautiously, make sure that we do have the best practices in place so we are able to take advantage of information that these other States that have more experience than we do have, and also trying to work with the Environmental Protection Agency because as I said, we believe their role is very critical in providing the background information and technical support.

Senator CARDIN. Thank you.

Senator Inhofe.

Senator INHOFE. Thank you, Mr. Chairman. I am sorry about the votes coming up. I think you are doing the right thing, though, although we would all like to have more time to ask questions.

Let me first of all talk to Commissioner Cloud and Director Neslin.

Director Neslin, you didn't say what percentage of your wells would be hydraulically fracked. Would either one of you have just a rough estimate as to the percentage in the State of Oklahoma and the State of Colorado that would be using that technology in their fracking?

Mr. NESLIN. In Colorado, it would be substantially all wells.

Senator INHOFE. OK.

Mr. CLOUD. In Oklahoma, it would be much the same. We have 185,000 active wells and 100,000 of them have been fracked, but the newer wells that utilize horizontal drilling are all hydraulically fracked.

Senator INHOFE. OK. I would just remind this panel up here, for those who weren't here in my opening statement, that we initiated the very first hydraulic fracturing in Oklahoma 60 years ago. So we know something about it.

Over the past few weeks, there has been a lot of focus on the disposal of both flow-back water in frack jobs and produced water from oil and gas wells, especially in Pennsylvania. Could you tell us how this water is disposed of in your two respective States, kind of briefly?

Mr. NESLIN. Certainly. In Colorado, a majority of the water is recycled and reused. If we are talking about the end disposal, final disposal of the water, about 60 percent is reinjected deep underground in permitted underground ejection wells. About 20 percent is evaporated. About 20 percent is discharged surface waters under State water quality permits that do contain environmental and health-based standards.

Mr. CLOUD. In Oklahoma, we recycle most of the frack water, but when it is used up, we have 10,500 injection wells that we put the water down, the fluids down in.

Senator INHOFE. So it is roughly the same as they are doing in Colorado, then.

How do your agencies respond to and investigate groundwater complaints, Director Neslin? Your agency recently investigated I think it was in Southern Colorado some complaints. Will you tell us how you do that?

Mr. NESLIN. Certainly. This is the event I mentioned that led to the hearing this last February. A couple of things about this are important. We got a complaint. We had an inspector on site in 16 hours collecting samples for laboratory analysis. This inspector has a Ph.D., in chemistry and 25 years of experience. He spent over 40 hours investigating the alleged contamination; worked with other members of our staff, including our engineering staff; wrote a 30-page report documenting his investigation and the various types of analysis that were used as part of that exercise.

When the landowner was dissatisfied with the conclusion that the staff had drawn, which was that there had been no impact from hydraulic fracturing, he received a full hearing, a half-day hearing, before our Commission within 60 days. Then our Commission unanimously affirmed the staff's finding.

So I think in terms of the rigor of the analysis, the timeliness of the work and the transparency of the process, this compares very well.

Senator INHOFE. OK.

About the same in Oklahoma?

Mr. CLOUD. It is about the same, Senator. We have an extensive field staff that are all over the State monitoring the wells and the well activity.

Senator INHOFE. OK. I only have about 30 seconds left. I would like to have each one of you talk about new technologies that are coming along. Is there a procedure? I will just confine this to Commissioner Cloud. Any kind of a procedure where you investigate these new technologies to what possible dangers could come up and what you do to mitigate these?

Mr. CLOUD. As I said, our staff is on top of it all the time, and we have a Complaint Division that if anybody has a complaint, like was outlined in Colorado, we are 24-hour accessible and we try to stay on top of every single instance.

Senator INHOFE. Thank you very much.

Dr. Volz, you made several comments about the risk levels and that type of thing. There was a very negative article in the *Pittsburgh Tribune Review* yesterday that I am sure that you have read by now, and I would like to ask that that be made a part of the record.

Senator CARDIN. Without objection, it will be included in the record.

Senator INHOFE. Thank you. Thank you, Mr. Chairman.

[The referenced document follows on page 376.]

Senator CARDIN. Senator Merkley.

Senator MERKLEY. Thank you, Mr. Chair.

Mr. Neslin, as I listened to your testimony, it sounded like there has never been any problem in Colorado and "We found no verified instance of hydraulic fracturing harming groundwater." How do we square that with the documentary I referred to earlier where Mike Markham takes and pours water out of his kitchen faucet, holds a cigarette lighter up to it, and after a few seconds, a ball of fire erupts out of the sink, almost enveloping Markham's head? The source of the flammable water and the substance of gas is a mining process called hydraulic fracturing.

How does that square with no verified instance of hydraulic harming groundwater?

Mr. NESLIN. Senator, we investigated that allegation. We investigated that well. The facts are that that water well was completed in a coal-bearing formation that contains what is called biogenic methane, methane unrelated to oil and gas development.

There are papers, published papers by the U.S. Geological Survey and the Colorado Geological Survey dating back more than 30 years verifying that fact, that in these formations there is naturally occurring biogenic methane not attributable to oil and gas development; not released by oil and gas development.

The allegations were thoroughly investigated. Laboratory analyses were done. The conclusion was drawn that this was biogenic methane not related to oil and gas development. As I say, it is based on not just the work of our staff, but scientific papers and geological surveys dating back decades.

Senator MERKLEY. So basically, if he had been running his water 30 years ago, he would have had exactly the same problem?

Mr. NESLIN. Yes, sir.

Senator MERKLEY. Interesting. Thank you for addressing that.

Dr. Volz, in your paper, you refer to a long list of chemicals that are coming out of the brine treatment facility: barium, strontium, bromide, benzene, glycol ether, chlorides and so forth. Now, was this facility, the brine treatment developed specifically to try to basically address the challenge of these flow-back fluids and clean them up?

Mr. VOLZ. Senator, this is an older flow-back fluid treatment facility that has been in operation for about 25 years, and up until about 5 years ago, only took care of conventional oil and gas fluids. Now, it is dealing with these Marcellus fluids.

Senator MERKLEY. So the technology in that facility is completely inappropriate or ineffective in terms of the flow-back fluids that are now being sent to it?

Mr. VOLZ. That is right, sir.

Senator MERKLEY. But if it was a newer facility, if you were looking at newer facility in Pennsylvania that had been designed specifically, we would find that all of these problems had been addressed?

Mr. VOLZ. I am not sure of that, sir. I think there needs to be a very definitive review of all the processes that are used by treatment facilities, not only in the State of Pennsylvania, because wastewater from the State of Pennsylvania is actually being treated by these plants and sewage treatment plants in New York, New Jersey, Maryland, Ohio and West Virginia, as well as Pennsylvania.

Senator MERKLEY. So I may have misinterpreted the pictures that were presented in your slides, but it looked like pipes coming out of the brine treatment facility into a creek and it is just dumping all of this ineffectively treated, highly contaminated dangerous stuff right into a creek on the surface in Pennsylvania. Is that actually what is happening?

Mr. VOLZ. That is exactly what is happening, sir. There is very little treatment that is done at that plant except to remove some of the barium. It is precipitated with a sulfate solution and the barium is lower, still high, but much lower than in the flow-back water, but there are many other contaminants that are not treated by the facility at all.

Senator MERKLEY. Why is Pennsylvania's Department allowing this highly contaminated fluid just to be put right into a creek?

Mr. VOLZ. I don't know, sir.

Senator MERKLEY. Thank you.

Thank you, Mr. Chair.

Senator CARDIN. Senator Sessions is the Ranking Republican Member of the Water and Wildlife Subcommittee.

Senator SESSIONS. Thank you. I didn't know who was next, but thank you.

Mr. Ubinger, the Federal Government regulates discharges in the streams and Pennsylvania regulates it. Maybe you would like to answer the question or Mr. Volz's comment that Pennsylvania is permitting pollutant discharges against the health and safety of the people into the water?

Mr. UBINGER. Senator, the Department of Environmental Protection in 2010——

Senator SESSIONS. Are you familiar with this incident that he is talking about?

Mr. UBINGER. Only from news reports about that facility. But what I was going to say is that the Department of Environmental Protection formulated a State-wide discharge limit for TDS and bromium and strontium that became effective either late last year or early this year. That standard is now in place. That standard, I think, would require newly issued permits to include that standard. It is a very stringent 500 parts per million standard.

I think one of the issues is that the permit cycle, which is typically 5 years, is running its course and thus far as far as I am aware, the Department has not asked anybody to accelerate the revision of those permits to put that standard in place.

Now, the import of that standard is that a number of the responsibility leaders in the industry have begun to recycle their flowback water by reinjecting it into new Marcellus well development. There are varying statistics, I am not sure which one would be accurate, but it is anywhere from 50 percent to 90 percent of flowback water, at least has some kind of recycling.

Senator SESSIONS. Well, could I just ask this, if it violates the Clean Water Act and the Clean Water Act would apply to that discharge, would it not, the Federal Clean Water Act?

Would it, yes or no?

Mr. UBINGER. Yes, it applies.

Senator SESSIONS. Somebody should investigate that and check on it and stop it if it is in violation, should it not?

Yes or no?

Mr. UBINGER. Yes, it should be.

Senator SESSIONS. All right. So he has made a complaint. I hope Pennsylvania will get around to doing it, instead of stopping hydraulic fracturing around the country.

Mr. UBINGER. Yes.

Senator SESSIONS. We are in a serious financial problem in America. I am worried about our economy. The surging gas prices make a difference. Natural gas absolutely can be an alternative to the liquid fuel we import, the gasoline. It burns cleaner. It is all-American. It is a lot cheaper. Engines that use it will pay for themselves over a period of time. The President I think indicated recently that he was interested in expanding natural gas for vehicles. I just think it has tremendous potential.

Too often, what we are seeing in Washington is the American people are suffering under high energy prices and all they hear from Washington is obstruction that makes those prices go up instead of down. People are worried about it.

I just would have to say that we need clean, lower-cost energy and I believe that is what natural gas is.

I would like to introduce, Mr. Chairman, into the record a statement from Dr. David Bolin, the deputy director of the State of Alabama's Oil and Gas Board. We have a large natural gas component and probably are the leading producer of coal-bed methane in the country, with thousands of wells. Over 20 or 30 years, we have never had a problem, according to Dr. Bolin who supervises that.

He went further. He took the media reports of leaking into groundwater allegations around the country. He called his colleagues around the country in those States and he has concluded that he has found no incidence in which groundwater has been polluted.

Do you know him, Mr. Cloud, Dr. Bolin?

Mr. CLOUD. I do not.

Senator SESSIONS. He has done this since 1982 when he joined the Board and has a master's degree and doctorate in water hydrology, not petroleum engineering. But I would just offer that for the record.

Just to paraphrase Senator Cornyn or to followup on it, I think we have to watch that the regulations and the lawsuits don't become a death by a thousand cuts.

Mr. Cloud, how many fracturing wells have been——

Mr. CLOUD. In Oklahoma, 100,000.

Senator SESSIONS. One-hundred thousand. I think it is 5,000 or 10,000 in Alabama. Nationwide, do you have any idea how many?

Mr. CLOUD. I believe the number is right at 1 million.

Senator SESSIONS. It is just huge numbers, and we have just got to be careful that at this time when we desperately need cleaner natural gas, all-American natural gas, keeping our wealth at home, that we don't create a greater bureaucracy, duplicative regulations that make it more difficult for us to fight back against high energy costs.

Thank you, Mr. Chairman, very much, and I am honored to be with you on this Subcommittee. You are a strong leader. You are a good experienced Member of Congress in the House and the Senate, and we are glad you are here.

Senator CARDIN. Thank you very much. I look forward to working with you, Senator Sessions.

Senator Whitehouse.

Senator WHITEHOUSE. I wanted to ask Mr. Cloud and Mr. Neslin, when Deputy Administrator Perciasepe was here, he said that companies that used diesel in fracking and did not seek a permit under the Safe Drinking Water Act would be in violation of that Act. Are you aware in either of your States that diesel is used as an element of the fracking fluid?

Mr. NESLIN. Senator, as I mentioned in my testimony, we are currently investigating that issue. Our investigation is not complete yet.

Senator WHITEHOUSE. Well, let me give Mr. Cloud a chance to answer before I go to another question.

Mr. CLOUD. We are much the same, Senator. But I just want to emphasize that we do not allow frack fluids into the water treatment facilities. The frack fluids are only recycled, and when they are used up, they are put into injection wells. So it doesn't reach our water supply, any frack fluid.

Senator WHITEHOUSE. You have no concern that the deployment of the frack fluid in the wells could ever reach your water supply?

Mr. CLOUD. We always have that concern, but we are assured by our rules and practices that that doesn't happen.

Senator WHITEHOUSE. You keep enough of a buffer between?

Mr. CLOUD. Yes. Production casing is required to be cemented 200 feet above the producing zone, so it can't reach. We have field inspectors that witness that process when it is undergone.

Senator WHITEHOUSE. Why isn't it helpful to simply know what is being used as the frack fluid so that you don't have to investigate where diesel is being used because the company would have reported it already since it is being injected into public land, basically?

Mr. CLOUD. Well, as some have discussed today, there is an IOGCC, an Interstate Oil and Gas Compact Commission and Groundwater Protection Council initiative that is voluntary right now, where companies, and it is just in its infancy, but we have had a great response. It has been outlined a little bit today, where people divulge, or companies divulge the type of fluids that they are using.

Senator WHITEHOUSE. I am new to this issue, as you can imagine. We don't do a lot of this in Rhode Island. But I have seen the stories on the news about families whose water, for instance, is suddenly compromised. In time, it is associated with fracking having taken place nearby. Are there different geological differences that explain why this might be happening in other places? Or is there a less well-developed technique? Or do you think that this is actually not related to fracking and just a matter of coincidence?

Mr. NESLIN. Senator, if I may answer that on behalf of Colorado, we get dozens of allegations a year that water wells have been contaminated. We inspect and investigate all of those rigorously. In some cases, we have found that contamination has occurred and that it is attributable to oil and gas development, not hydraulic fracturing. Typically, it is a spill. It is a leak; might have been a failure of the cement job.

In most instances or in many instances, we find that there has been no contamination; that the conditions that are being complained of are bacterial contamination, a problem with maintaining the water well. In other instances, as I mentioned in response to another question, there may be an impact from natural gas, but it is biogenic natural gas, swamp gas from decaying organic material, not attributable to oil and gas development.

Mr. CLOUD. Speaking for Oklahoma, we have been doing this process for a long time and there has not been one single documented instance of contamination to groundwater or drinking water as a result of this process.

Senator WHITEHOUSE. My time has expired.

Thank you very much, Mr. Chairman.

Thank you all, gentlemen, for your testimony.

Senator CARDIN. Thank you.

Senator Boozman, thank you for your patience. You are recognized.

Senator BOOZMAN. Thank you, Mr. Chairman, very much.

Again, I appreciate all of you being here. I think we have heard a lot about some of the potential problems with the process, but also some of the solutions. One of the things that Mr. Cloud and Mr. Neslin mentioned was the STRONGER review process. What I would like for you to do is very briefly, if you could, talk about the make-up of the review teams, the observers, the evaluations and followup procedures of STRONGER.

Then also I believe that sometimes EPA is involved and DOE, you can talk a little bit about that.

Mr. NESLIN. If I might begin, STRONGER is a unique group in that it is comprised one-third of State regulators, one-third representatives of the industry, one-third of environmental representatives. Therefore, on a study, a STRONGER review, one-third of the review team will be from each of those groups. One-third of the observers will be from each of those groups.

It is also a collaborative process, so rather than a group that issues majority and minority positions, the participants work collaboratively to reach a common assessment and a common conclusion.

Then it is a transparent process in which these reports are issued typically within 60 days after the review is concluded and are posted on the Website and publicly available.

Mr. CLOUD. Mr. Neslin did a good job of outlining the make-up of the Board. One-third of the people in STRONGER that reviewed Oklahoma, it was a Texas regulatory Commissioner and then a noted critic of the domestic oil and gas industry, and the Independent Petroleum Association of America. But official observers to the process and contributors to that process were the Sierra Club and the EPA, and STRONGER is funded partially by EPA and DOE.

Senator BOOZMAN. Thank you, Mr. Chairman.

Senator CARDIN. Thank you.

Let me thank all of our witnesses. I think this panel has been extremely helpful. There are still a lot of questions I think we need to deal with.

As I was listening to the testimony, I was curious and I might be submitting some questions on this, as to what precautions are taken in regards to abandoned drilling sites to make sure that they are not only safely sealed, but the impact that the vacated cavity could have on geological activities. I am not, again, a geologist, but I would be interested as to whether we are at least mindful of these types of issues as we are drilling more and more wells with the amount of natural gas that we have.

So I think there are questions that need to be answered. I do want to compliment the States of Colorado and Oklahoma who have taken aggressive action to protect their public health of their citizens. I think we need to learn from the best practices and we have seen some of that sort of catch on in other States.

We do have a framework here between the Federal Government and the State government. Our committee will investigate to see whether that is strong enough under existing law or whether new laws are needed.

I certainly appreciate the testimony from the Environmental Protection Agency and it looks like they are aggressively dealing with some of the open issues on public health.

So we will be following up on the questions that have been asked. The record is open for additional questions that may be asked. If that is done, I would ask you all to respond in a timely way.

With that, the joint hearing of the committee and subcommittee will be adjourned.

Thank you all very much.

[Whereupon, at 12:12 p.m. the committee and subcommittee were adjourned.]

[Documents related to Marcellus Shale Development EPA Region III, have been archived and may be found in committee files.]

[Additional statements submitted for the record follow:]

Congressman Dan Boren
April 12, 2011
Submitted Testimony
U.S. Senate Environment and Public Works Committee
Full Committee and Subcommittee on Water and Wildlife, "Natural Gas Drilling: Public Health and Environmental Impacts."

Madam Chairman, thank you for holding this hearing today. My name is Congressman Dan Boren and I represent the second Congressional District of Oklahoma in the United States House of Representatives. As a member of the House of Representatives, I sit on the House Natural Resources Committee which has primary jurisdiction over energy policy on America's federal lands and regulates energy development off America's coasts. Additionally, I co-chair the House Natural Gas Caucus which is a bipartisan caucus made up of more than 70 members of the House of Representatives. The primary goal of the House Natural Gas Caucus is to promote responsible development of domestic natural gas and advocate for legislation that encourages the production, transmission, distribution, and use of this generational changing fuel.

Madam Chairman for more than a century, my state of Oklahoma has been a leader and pioneer within the natural gas industry. Oklahoma is the nation's second-largest producer of natural gas and has the second-greatest number of active drilling rigs. A large portion of our funding for secondary and elementary education comes directly from royalty and lease sales tied to natural gas. As reported by Forbes Magazine, Oklahoma based Devon Energy Corporation, Chesapeake Energy Corporation, and SandRidge Energy Corporation are the largest private oil and natural gas related companies in the nation. These companies and the many independent oil and gas producers within my state create and supply millions of dollars in economic activity for thousands of Oklahomans, which in-turn has led to a vibrant and thriving middle class. Currently Oklahoma has one of the lowest unemployment rates in the country, 6.8%, and that low unemployment rate is directly tied to the natural gas industry.

However, despite all of these positives and a century long record of environmental stewardship, I believe that the energy industry, and particularly the natural gas industry, is under attack by those opposed to domestic energy development. And at the center of this campaign is a policy designed to shut down the natural gas industry and to blur the facts surrounding the extraction process used to harvest natural gas: hydraulic fracturing.

Madam Chairman, regardless of what the naysayers might infer at this hearing, hydraulic fracturing is not new and has actually been around for more than half a century. Introduced by Standard Oil in the late 1940's, the first commercially fractured well took place in Stephen's County, Oklahoma in 1949. Over the next sixty years, 2.5 million gas and oil wells have been developed using the hydraulic fracturing process. This energy development has led to the harvesting of over 9 billion barrels of oil and more than 700 trillion square feet of natural gas. In fact, some of America's largest natural gas fields would not, and could not, be developed without the use of the hydraulic fracturing process. Energy fields such as the Pine Island Field in Louisiana, the Anadarko Basin in northwestern Oklahoma, and the entire San Juan Basin in New Mexico would be rendered useless without the hydraulic fracturing process.

The main criticism argued by the anti-natural gas consortium in America is that the process of hydraulically fracturing a gas well contaminates ground water and dirties America's precious drinking supply. Nothing could be further from the truth. In the sixty year history of hydraulic fracturing, there hasn't been a single incident of ground water contamination directly linked to the process of hydraulic fracturing. Over two million fracking jobs and not one incident where hydraulic fracturing has been directly linked to ground water contamination. I ask you to find me another industry with a better safety record than that? But the opponents of natural gas development pass over that fact – and Madam Chairman it is a fact. I'd like to submit to you for the record, official statements from almost a dozen state regulators and even the Environmental Protection Agency clarifying this specific fact – that there have been zero incidents of water contaminations linked to hydraulic fracturing.

Environmental Protection Agency (EPA):
"In its review of incidents of drinking water well contamination believed to be associated with hydraulic fracturing, EPA found no confirmed cases that are linked to fracturing fluid injection into CBM wells or subsequent underground movement of fracturing fluids. Further, although thousands of CBM wells are fractured annually, EPA did not find confirmed evidence that drinking water wells have been contaminated by hydraulic fracturing..." -2002 EPA, Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs; National Study, Final Report

Alabama Regulator:
"There have been no documented cases of drinking water contamination that have resulted from hydraulic fracturing operations to stimulate oil and gas wells in the State of Alabama." - Nick Tew, Ph.D., P.G, Alabama State Geologist & Oil and Gas Supervisor

Alaska Regulator:
"There have been no verified cases of harm to ground water in the State of Alaska as a result of hydraulic fracturing." - Cathy Forester, Commissioner, Alaska Oil and Gas Conservation Commission

Colorado Regulator:
"To the knowledge of the Colorado Oil and Gas Conservation Commission staff, there has been no verified instance of harm to groundwater caused by hydraulic fracturing in Colorado."
-David Neslin, Director, Colorado Oil and Gas Conservation Commission

Indiana Regulator:
"There have been no instances where the Division of Oil and Gas has verified that harm to groundwater has ever been found to be the result of hydraulic fracturing in Indiana."- Herschel McDivitt, Director, Indiana Department of Natural Resources

Louisiana Regulator:
"The Louisiana Office of Conservation is unaware of any instance of harm to groundwater in the State of Louisiana caused by the practice of hydraulic fracturing."- James Welsh, Commissioner of Conservation, Louisiana Department of Natural Resources

Michigan Regulator:
"There is no indication that hydraulic fracturing has ever caused damage to ground water or other resources in Michigan." - Harold Fitch, Director, Office of Geological Survey, Michigan Department of Environmental Quality

Oklahoma Regulator:
"You asked whether there has been a verified instance of harm to groundwater in our state from the practice of hydraulic fracturing - The answer in no." - Lori Wrotenbery, Director, Oil and Gas Conservation Division for state of Oklahoma

Tennessee Regulator:
"We have had no reports of well damage due to fracking." - Paul Schmierbach, Manager, Tennessee Department of Environmental Conservation

Texas Regulator:
"Though hydraulic fracturing has been used for over 60 years in Texas, our Railroad Commission records do not reflect a single documented surface or groundwater contamination case associated with hydraulic fracturing."- Victor G. Carrillo, Chairman, Railroad Commission of Texas

South Dakota Regulator:
"In the 41 years that I have supervised oil and gas exploration, production and development in South Dakota, no documented case of water well or aquifer damage by the fracking of oil or gas wells, has been brought to my attention. Nor am I aware of any such cases before my time." - Fred Steece, Oil and Gas Supervisor, South Dakota Department of Environment and Natural Resource

Wyoming Regulator:
"No documented cases of groundwater contamination from fracture stimulations in Wyoming." - Rick Marvel, Engineering Manager, Wyoming Oil and Gas Conservation Commission and Tom Doll, Oil and Gas Commission Supervisor, Wyoming Oil and Gas Conservation Commission

Two million wells and we have had only a handful of major incidents – none of which have been the result of the hydraulic fracturing process. While some will claim that now we are moving into "new areas" and "drilling on more sensitive drinking water aquifers" – that alone is not true either.

The state of Oklahoma is located on top of the Ogallala Aquifer, also known as the High Plains Aquifer. The Ogallala Aquifer is one of the largest aquifers in the world and it covers an area of approximately 174,000 miles. It is located under eight states including South Dakota, Nebraska, Wyoming, Colorado, Kansas, Oklahoma, New Mexico, and Texas. This aquifer is the water supply to the bread basket of the world and is a vital water supply to millions of farmers who tap it to feed their crops. And in over 60 years of hydraulic fracturing on and around the Ogallala Aquifer, there has not been one substantiated incident of aquifer contamination as a result of hydraulic fracturing.

Madam Chairman, in an effort to make my remarks concise I will leave you with these final points. We have been fracking wells in the United States of America for more than 60 years. And in the 60 years that this technology has existed, there has not been one substantiated incident of ground water contamination linked to hydraulic fracturing. Don't just take my word for it, take the words of the EPA and over a dozen state regulators.

Thank you for holding this hearing.

TESTIMONY SUBMITTED FOR

THE JOINT HEARING OF
THE U.S. SENATE COMMITTEE ON ENVIRONMENT AND PUBLIC WORKS
WITH THE SUBCOMMITTEE ON WATER AND WILDLIFE
ENTITLED
"NATURAL GAS DRILLING: PUBLIC HEALTH AND ENVIRONMENTAL IMPACTS"

BY
DAVID E. BOLIN, PH.D.
DEPUTY DIRECTOR OF THE STATE OIL AND GAS BOARD OF ALABAMA

APRIL 12, 2011

Introduction

My name is David E. Bolin. I am the Deputy Director of the State of Alabama Oil and Gas Board (Board). I am representing the Board and the State of Alabama and would like to provide my perspective as a state oil and gas regulator regarding the public health and environmental impacts of natural gas drilling, which is the subject of this joint hearing.

Relevant Training & Work Experience

I have been employed by the State of Alabama since July 1979 and have served in technical and supervisory roles with the Board since 1982. I have a Master's and a Doctorate degree in Ground Water Hydrology as well as a second Master's degree in Petroleum Engineering.

My first responsibility with the Board was to develop the State's Class II Underground Injection Control (UIC) Program, pursuant to Section 1425 of the Safe Drinking Water Act (SDWA), in order to obtain primary enforcement responsibility for that program from the U.S. Environmental Protection Agency (EPA). The Board's program, approved by EPA in August 1982, was the sixth UIC program approved in the nation. Since that time, I have had supervisory responsibility for the Class II UIC Program and all other ground water protection programs under the Board's jurisdiction.

During my tenure with the Board, I have also been actively involved in the Ground Water Protection Council and its predecessor, the Underground Injection Practices Council. I am a Charter Member of the Board of Directors and have served as a Member continuously since 1983. During that time, I have served in various leadership roles to include President of the organizaton. Currently, I am serving as the President of the Ground Water Research & Education Foundation, a research arm of the Council. I am also a long-standing member of the Energy Resources, Research and Technology Committee of the Interstate Oil & Gas Compact Commission.

Importance of Oil and Natural Gas

Oil and natural gas are two of the primary energy sources in the United States. According to the U.S. Energy Information Administration, the use of oil accounted for 37 percent of the energy used in 2009, while natural gas use accounted for 25 percent (http://www.eia.doe.gov/energy_in_brief/major_energy_sources_and_users.cfm). The remaining 38 percent came from coal, nuclear fuel, and renewable energy sources.

Consumption of oil and natural gas in the U.S. is expected to continue to increase in the long term. To a certain extent, this increased demand is expected to be offset by increases in unconventional gas production. The U.S. Energy Information Administration is now "projecting a substantial increase in (the world's tight gas, shale gas, and coalbed methane resource base)—especially in the United States, but also in Canada and China." It further states that "[i]n the United States, one of the keys to increasing natural gas production has been advances in horizontal drilling and hydraulic fracturing technologies, which have made it possible to develop the country's vast shale gas resources, and have helped to increase total U.S. natural gas resources by almost 50 percent over the past decade." (http://www.eia.doe.gov/oiaf/ieo/nat_gas.html)

The oil and gas industry is also a critical component in the economy of our State, as well as the nation. Crude oil and natural gas account for more than 60 percent of the energy consumed in the United States. While Alabama's population is ranked 23rd in the nation, our total per capita energy consumption is 7th. Therefore, the ready availability of crude oil and natural gas supplies within the State is paramount to our continued security and economic well being.

The oil and gas industry in Alabama is a major contributor in the development and production of oil and gas resources in the United States. Currently, our State is ranked 14th in the nation in natural gas production and 15th in crude oil production. Alabama's annual gas production has ranked as high as 9th, and its oil production as high as 13th.

In addition to the national energy and security implications, the State's oil and gas industry generates substantial revenues for the direct benefit of the citizens of the State. In a typical year, $250 to $500 million is received by the direct benefit of the citizens of the State as a result of oil and gas production. At times, these revenues have approached an amount equivalent to 30 percent of the State's General Fund Appropriations. Therefore, the oil and gas industry is a significant contributor to the State's economy. The State Oil and Gas Board, established in 1945, guides the development of these resources and oversees the infrastructure that allows production of the State's hydrocarbon resources.

Alabama's Oil & Gas Industry

Alabama became an oil and gas producing state in 1944 with the discovery of oil in the southwest area of the State. Exploration and development have continued since that time to the point that Alabama now has a broad and diverse oil and gas industry that includes onshore and offshore operations, as well as conventional and unconventional hydrocarbon resources. As such, Alabama serves as an excellent representative for all of the oil and gas producing states.

Since the late 1980's, the principal focus of oil and gas exploration in our State has shifted from conventional to unconventional resources; more specifically, to the development of our coalbed methane resources. Coalbed methane has become a major contributor to Alabama's oil and gas industry in last 20 years. Since the establishment of the Board, approximately 60 percent of the oil and gas wells drilled in Alabama have been coalbed methane wells. Alabama has been a national leader in coalbed methane operations and was the first state to promulgate regulations addressing coalbed methane operations. In recent years, applications for permits to drill coalbed methane wells have accounted for as much as 85 percent of the total permits issued. In 2010, 42 percent of the state's total gas production was coalbed methane gas. Similar developments in coalbed methane activity have occurred in a number of other states.

Exploration for shale gas is a new trend in Alabama. To date, shale gas projects in the State have not proven to be economically feasible. Similar projects in other parts of the country, such as the development of the Barnett Shale in the Fort Worth basin in Texas, have added substantial gas reserves to the nation's resource base. Given the wide distribution of shale formations in the State, it is believed that substantial gas reserves could also be developed in Alabama if the right combination of drilling and stimulation techniques is employed.

Ground Water Protection: Regulatory Framework

It is the mission of the Board to promote the conservation of and prevent the waste of Alabama's oil and gas resources, while ensuring the protection of the State's ground-water resources and the environment. This mission is accomplished through the promulgation and enforcement of rules and regulations and regulatory actions at public hearings that protect correlative rights of owners and other stakeholders and provide safe and orderly development.

As I mentioned previously, my first responsibility with the Board was to develop the State's Class II Underground Injection Control (UIC) Program, pursuant to Section 1425 of the Safe Drinking Water Act (SDWA), in order to obtain primary enforcement responsibility for that program from the U.S. Environmental Protection Agency (EPA). The EPA made a determination that our Program accomplished the objectives of the SDWA, that being to protect underground sources of drinking water from endangerment that could result from improper injection of fluids, and was, therefore, approved by EPA in August 1982.

Obtaining primacy for the Class II UIC Program, however, was not the beginning of the Board's ground-water protection programs. Such programs, to include the regulation and approval of hydraulic fracturing operations, have been actively implemented continually since the Board was established in 1945. The Board has a staff of geologists and petroleum engineers to provide technical expertise and to otherwise assist in its duties. In the original act establishing the Board, one of the Board's duties was to "prevent the pollution of fresh water." Protecting drinking water resources is part and parcel of every state's conservation statute (i.e. the prevention of waste and the loss of critical natural resources without economic or beneficial use). These mandates to protect drinking water and other natural resources preceded the establishment of the SDWA.

Although the Board in Alabama had been adequately protecting ground water for many years, it elected to apply for primary regulatory authority for this federal program in order to prevent dual regulatory requirements and to eliminate extended time delays associated with federal permitting and decision-making so that oil and gas development could proceed in an orderly manner and to prevent any waste that would otherwise be incurred.

In addition to the UIC regulations, the Board, along with our regulatory counterparts in other oil and gas producing states, have other regulations that provide for the protection of our ground water resources. To document this fact, the Ground Water Protection Council published a report, entitled *State Oil and Natural Gas Regulations Designed to Protect Water Resources* (http://www.gwpc.org/elibrary/documents/general/State%20Oil%20and%20Gas%20Regulations%20Designed%20to%20Protect%20Water%20Resources.pdf) in May 2009. Based on a regulatory review and analysis conducted as a part of the study, the GWPC concluded that "[s]tate oil and gas regulations are adequately designed to directly protect water resources through the application of specific programmatic elements such as permitting, well construction, well plugging, and temporary abandonment requirements."

Hydraulic Fracturing

Hydraulic fracturing is a process that has been used in the oil and gas industry for more than 60 years to induce fractures in the producing formation to stimulate and increase the flow of oil and gas to the wellbore. Use of such technology is a key to the commercial development of unconventional gas resources such as coalbed methane and shale gas. For example, coalbed methane production in Alabama is only economical if the coal seams can be hydraulically fractured. However, the use of this stimulation method has not been without controversy or concern, particularly in its recent use in shallow, unconventional reservoirs. Typical issues include chemical constituents in the fracturing fluid, the fate of the fluids, and impacts on local water resources.

As noted earlier, Alabama has been at the forefront of the development of coalbed methane resources. At the same time, the hydraulic fracturing of coalbed methane gas wells was the subject of an extended, high-profile litigation. In 1994, a Florida-based environmental group, the Legal Environmental Assistance Foundation (LEAF), filed a petition with EPA requesting that EPA take over primacy under the State of Alabama's UIC program. LEAF contended that hydraulic fracturing associated with methane gas production was an injection under the SDWA and therefore should be subject to regulation under the State of Alabama's UIC program.

Following EPA's rejection of its petition in 1995, LEAF filed an appeal with the 11th U.S. Circuit Court of Appeals. In 1997 the 11th Circuit ruled in favor of LEAF holding that hydraulic fracturing constitutes underground injection and therefore must be regulated as such under the SWDA. The court did not address the issue of risk of harm associated with fracturing or reach any finding of actual harm to drinking water, deciding the issue strictly on the definitional issue. As a result of the court's decision and subsequent rulings, the State of Alabama in 1999 submitted a revised Class II UIC Program package consistent with the Court's rulings and subsequent orders. The EPA approved the Alabama program. A subsequent LEAF effort before the 11th U.S. Circuit arguing that EPA erred in approving the Alabama program failed as did an application for writ of certiorari before the U.S. Supreme Court.

Although EPA had never regarded hydraulic fracturing as an "underground injection" under the SDWA, and so argued before the 11th Circuit Court of Appeals, the EPA decided to let the decision stand and not appeal the court's decision. The result has been higher operating costs for producers of coalbed methane in Alabama and significantly higher administrative costs by the State of Alabama in administering its Class II UIC Program.

Thus, the LEAF case launched an effort, based solely on a definitional issue without any finding of contamination or harm, to tighten up the regulation of hydraulic fracturing nationally.

In 1999, the Ground Water Protection Council conducted a survey of state regulatory agencies regarding the inventory and extent of hydraulic fracturing in coalbed methane wells in oil and gas producing states. The principal conclusion of that survey was that "[t]here are no indications from this survey to suggest that public health is at risk as a result of the hydraulic fracturing of coalbeds used for the production of methane gas."

Additionally, in 2002, the IOGCC completed a survey of oil and natural gas producing states that provides an understanding of hydraulic fracturing and its role in the completion of oil and natural gas wells in the United States. Principal findings of this survey reveal that the technique has been in widespread, common use for nearly 60 years – the technique gained its current widespread popularity as a production technique in the 1940s. Approximately 35,000 wells are hydraulically fractured annually in this country with close to one million wells having been hydraulically fractured in the United States since the technique's inception with no documented harm to groundwater. Hydraulic fracturing has been regulated by the states since its inception. A principal focus of state oil and gas regulatory programs is on protecting ground and surface water resources. The survey reveals hydraulic fracturing of natural gas and oil wells is a process that is well understood and well regulated by the petroleum producing states.

In June 2004, EPA published a final report summarizing a study to evaluate the potential threat to underground sources of drinking water (USDWs) from the injection of hydraulic fracturing fluids into coalbed methane (CBM) production wells. In that report, EPA concluded that "additional or further study is not warranted at this time . . ." and "that the injection of hydraulic fracturing fluids into CBM wells poses minimal threat to USDWs."

EPA further stated in its summary of the study that "[i]n its review of incidents of drinking water well contamination believed to be associated with hydraulic fracturing, EPA found no confirmed cases that are linked to fracturing fluid injection into CBM wells or subsequent underground movement of fracturing fluids. Further, although thousands of CBM wells are fractured annually, EPA did not find confirmed evidence that drinking water wells have been contaminated by hydraulic fracturing fluid injection into CBM wells. Where fluids are injected, EPA believes that groundwater production, combined with mitigating effects of dilution and dispersion, adsorption, and biodegradation, minimize the possibility that chemicals included in fracturing fluids would adversely affect USDWs."

On June 4, 2009, Scott Kell, testified on behalf of the Ground Water Protection Council before the Subcommittee on Energy and Mineral Resources of the House Committee on Natural Resources regarding the states' efforts to protect water resources (See Attachment A.). During his testimony, he stated that, "[i]n recent months, the states have become aware of press reports and websites alleging that six states have documented over one thousand incidents of ground water contamination resulting from the practice of hydraulic fracturing. Such reports are not accurate. Attached to my testimony are signed statements from state officials representing Ohio, Pennsylvania, New Mexico, Alabama, and Texas, responding to these allegations."

Based on these studies and signed statements from state regulators, as well as communications with my counterparts in other states, I am not aware of a single documented case of ground water contamination resulting from hydraulic fracturing operations. This record is a testament to the regulatory oversight that has been provided by the states, given that an estimated 1.3 million wells have been hydraulic fractured over the past six decades.

Current Initiatives

In spite of the states' excellent regulatory record with respect to hydraulic fracturing, questions and concerns continue to be raised regarding the use of this stimulation technique. It appears that the concerns expressed are more often a result of a lack of information or understanding regarding the details of a given hydraulic fracturing operation. More specifically, the major issue has been that the public is unable to obtain lists of chemical constituents being used in a given fracturing operation.

To that end, a website entitled, "FracFocus Chemical Disclosure Registry" has been developed and launched. The website is a joint effort of the Ground Water Protection Council and the Interstate Oil & Gas Compact Commission. According to information contained on the site (http://www.hydraulicfracturingdisclosure.org/), the "website provides a central location for public and industry to communicate and relay information on the chemicals used during the process of hydraulic fracturing of oil and gas wells. . . . (The) website provides a means for industry to voluntarily supply hydraulic fracturing chemical data in a consistent and centralized location. This open process assists both the public and industry by supplying a centralized repository for the data . . .". In addition to specific well information, the site will provide educational information about chemical formulae, the process of hydraulic fracturing, the means used to protect ground water during hydraulic fracturing, and other relevant information.

State versus Federal Regulation of Oil and Gas Operations

Historically, oil and gas exploration and development has been successfully regulated by the states. Over many decades, each producing state has typically developed a comprehensive set of rules and regulations that not only provide for safe and effective recovery of the hydrocarbons resources, but also fully ensures the protection of human health as well as the environment. Such rules are tailored to specifically address technical and regulatory issues that are unique to a given regional area, hydrocarbon type, geologic formation, production characteristics, public safety issues, and environmental considerations. In Alabama, specific rules are designed and implemented even to the individual oil and gas field level to adequately address the variabilities that are known to exist among the oil and gas fields. Regulatory oversight is provided by highly trained and experienced engineers, geologists, and field inspectors to ensure compliance by all active operators. Such an approach has proven to be a very successful model for the effective regulation of the oil and gas industry throughout the years and is much preferred over a federal "one-size-fits-all" model.

Recently, there has been a movement calling for federal regulation of hydraulic fracturing. The states are convinced that any such federal regulation would be duplicative, unnecessary, and unwarranted. State regulatory agencies have a proven track record with the regulations that are in place now. These regulations have proven sufficient to adequately protect public health and the environment from hydraulic fracturing operations associated with the oil and gas development.

Alabama is in a unique position to understand the ramifications of having additional federal requirements added on top of existing state regulations. Those requirements were generated as a result of the LEAF matter and ultimately required the Board to revise its Class II UIC Program. The added federal requirements resulted in substantially increased administrative and production costs with no public health or environmental benefit.

Summary

The subject of this hearing, Natural Gas Drilling: Public Health and Environmental Impacts, is a timely subject. Natural gas currently supplies 25 percent of the United States' energy needs. As such, natural gas is of vital importance to the nation and the states not only as an energy source but also from an economical standpoint as well. Natural gas consumption is anticipated to continue to increase in the long term. Therefore, the exploration for and production of this critical energy source needs to be given a high priority. At the same time, responsible energy development must be accompanied by a similar priority being placed on the protection of public health and the environment.

Protection of the nation's ground water resources has been an integral part of the states' comprehensive regulatory programs that provide oversight of the operations conducted by the oil and gas industry. Over many decades, state regulatory agencies have ensured that underground sources of drinking water and the environment are protected from activities associated with oil and gas operations.

The development of unconventional natural gas resources such as coalbed methane and shale gas has becoming an increasingly important and growing segment of the nation's natural gas reserves. In order to "unlock" these resources, artificial flow paths must be generated in the target formations by a process called hydraulic fracturing. While there have been questions and concerns regarding chemical constituents used and the potential for impact to ground water, there has been no documented case of contamination resulting from approximately 1.3 million wells being hydraulically fractured since 1947. A public information and education initiative is currently underway by the Ground Water Protection Council and the Interstate Oil & Gas Compact Commission to address the expressed concern by developing a Chemical Disclosure Registry.

The states have successfully regulated the oil and gas industry for many decades. The states currently have adequate rules and regulations in place, and a high priority has been placed on protecting ground water and the environment. The states are well positioned to ensure regulatory compliance, and the technical experts within the state regulatory agencies have the experience and expertise to fully address any public health or environmental issue that may arise. It is our position that any additional federal regulation would be duplicative, unnecessary, unwarranted, and would provide no public health or environmental benefit.

I want to express my appreciation for the opportunity to submit my comments for consideration in this hearing. If I can provide any additional information, please do not hesitate to ask.

Attachment A – Bolin Testimony for the U.S. Senate Committee on Environment and Public Works with the Subcommittee on Water and Wildlife, April 12, 2011

STATEMENT OF
SCOTT KELL
ON BEHALF OF THE
GROUND WATER PROTECTION COUNCIL

HOUSE COMMITTEE ON NATURAL RESOURCES
SUBCOMMITTEE ON ENERGY AND MINERAL RESOURCES
WASHINGTON, D.C.
JUNE 4, 2009

Mr. Chairman, thank you for the opportunity to testify today. My name is Scott Kell. I am President of the Ground Water Protection Council (GWPC) and appear here today on its behalf. I am also Deputy Chief of the Ohio Department of Natural Resources Division of Mineral Resources Management. With me today are Mike Paque, Executive Director of the GWPC, Dave Bolin, Assistant Director of the Alabama Oil and Gas Board, and Lori Wrotenbery, Director of the Oklahoma Corporation Commission's Oil and Gas Conservation Division. Within our respective States, we are responsible for implementing the state regulations governing the exploration and development of oil and natural gas resources. First and foremost, we are resource protection professionals committed to stewardship of water resources in the exercise of our authority.

The GWPC is a non-profit association of state agencies responsible for environmental safeguards related to ground water. The members of the association consist of state ground water and underground injection control regulators. The GWPC provides a forum through which its state members work with federal scientists and regulators, environmental groups, industry, and other stakeholders to advance protection of ground water resources through development of policy and regulation that is based on sound science. I have included a list of the GWPC Board of Directors in our written submission.

The GWPC understands that our nation's water and energy needs are intertwined, and that demand for both resources is increasing. Smart energy policy will consider and minimize impacts to water resources.

With respect to the protection of water resources, the GWPC recently published two reports of note. The first of these reports is called *Modern Shale Gas Development in the United States: A Primer* (*http://www.gwpc.org/e-library/documents/general/Shale%20Gas%20Primer%202009.pdf*). The primer discusses the regulatory framework, policy issues, and technical aspects of developing unconventional shale gas resources. As you know, there are numerous deep shale gas basins in the United States, which contain trillions of cubic feet of natural gas. The environmentally responsible development of these resources is of critical importance to the energy security of the U.S. Recently, however, there has been concern raised about the methods used to tap these valuable resources. Technologies such as hydraulic fracturing have been characterized as being environmentally risky and inadequately regulated. The primer is designed to provide accurate technical information to assist policy makers in their understanding of these issues.

In recent months, the states have become aware of press reports and websites alleging that six states have documented over one thousand incidents of ground water contamination resulting from the practice of hydraulic fracturing. Such reports are not accurate. Attached to my testimony are signed statements from state officials representing Ohio, Pennsylvania, New Mexico, Alabama, and Texas, responding to these allegations.

From the standpoint of the GWPC, the most critical issue is protection of water resources. As such, our goal is to ensure that oil and gas development is managed in a way that does not create unnecessary and unwarranted risks to water. As a state regulatory official, I can assure you that our regulations are focused on this task. This leads me to the second report the GWPC has recently published.

This report, entitled *State Oil and Gas Regulations Designed to Protect Water Resources,* (http://www.gwpc.org/e-library/documents/general/Oil%20and%20Gas%20Regulation%20Report%20Final%20with%20Cover%205-27-2009.pdf) evaluates regulations implemented by state oil and gas regulatory agencies as they relate to the protection of water. To prepare this report, the GWPC reviewed the regulations of the twenty-seven states that, when combined, account for more than 99.8% of all the oil and natural gas extracted in the U.S. annually. To prepare this report, each state's regulatory requirements were studied with respect to their water protection capacity. The study evaluated regulated processes such as well drilling, construction, and plugging, above-ground storage tanks, pits and a number of other topics. The report also contains a statistical analysis of state regulations. As a result of our regulatory review and analysis, the GWPC concluded that state oil and gas regulations are adequately designed to directly protect water resources through the application of specific programmatic elements such as permitting, well construction, hydraulic fracturing, waste handling, and well plugging requirements. While State regulations are generally adequate, the GWPC report makes the following recommendations.

First, a study of effective hydraulic fracturing practices should be considered for the purpose of developing Best Management Practices (BMPs) that can be adjusted to fit the specific conditions of individual states. A one-size-fits-all federal program is not the most effective way to regulate in this area. BMPs related to hydraulic fracturing would assist states and operators in ensuring the safety of the practice. Of special concern are zones in close proximity to underground sources of drinking water, as determined by the state regulatory authority.

Second, the state review process conducted by the national non-profit organization State Review of Oil and Natural Gas Environmental Regulations (STRONGER) is an effective tool in assessing the capability of state programs to manage exploration and production waste and in measuring program improvement over time. This process should be expanded, where appropriate, to include state oil and gas programmatic elements not covered by the current state review guidelines. STRONGER is currently convening a stakeholder workgroup to consider drafting guidelines for state regulation of hydraulic fracturing.

Finally, the GWPC concludes that implementation and advancement of electronic data management systems has enhanced state regulatory capacity and focus. However, further work is needed in the areas of paper-to-digital data conversion and inclusion of more environmental, or water related data. States should continue to develop comprehensive electronic data management systems and incorporate widely scattered environmental data as expeditiously as possible. Federal agencies should provide financial assistance to states in these efforts.

In conclusion, Mr. Chairman and Committee Members, we believe that state regulations are designed to provide the level of water protection needed to assure water resources remain both viable and available. The states are continuously striving to improve both the regulatory language and the programmatic tools used to implement that language. In this regard, the GWPC will continue to assist states with their regulatory needs for the purpose of protecting water, our most vital natural resource.

Thank you.

DISCLOSURE REQUIREMENT
Required by House Rule XI, clause 2(g)
and Rules of the Committee on Resources

1. Name: **Scott R. Kell**

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4. Organization you are representing: **The Ground Water Protection Council**

5. Any training or educational certificates, diplomas or degrees or other educational experiences which add to your qualifications to testify on or knowledge of the subject matter of the hearing: **Bachelor's Degree in Geology from Mount Union College and a Masters Degree in Geology from Kent State University.**

6. Any professional licenses, certifications, or affiliations held which are relevant to your qualifications to testify on or knowledge of the subject matter of the hearing:

7. Any employment, occupation, ownership in a firm or business, or work-related experiences which relate to your qualifications to testify on or knowledge of the subject matter of the hearing:

8. Any offices, elected positions, or representational capacity held in the organization on whose behalf you are testifying: **Chief of the Ohio Department of Natural Resources, Division of Mineral Resources Management; President of the Ground Water Protection Council**

9. Any federal grants or contracts (including subgrants or subcontracts) from the Department of the Interior (and /or other agencies invited) which you have received in the last three years, including the source and the amount of each grant or contract: **Office of Surface Mining, 2008 National Technology Transfer Grant, RBDMS-W, $200,000**

10. Any federal grants or contracts (including subgrants or subcontracts) the Department of the Interior (and /or other agencies invited) which were received in the last three years by the **organization(s) which you represent** at this hearing, including the source and amount of each grant or contract: **Office of Surface Mining, 2008 National Technology Transfer Grant, RBDMS-W, $200,000**

11. Any other information you wish to convey which might aid the members of the Committee to better understand the context of your testimony:

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Attachment 1 – GWPC Testimony to the House Committee on Natural Resources, Subcommittee on energy and Mineral Resources, June 4, 2009

State Oil and Natural Gas Regulations Designed to Protect Water Resources

EXECUTIVE SUMMARY

Over the past several years the GWPC has been asked, "Do state oil and gas regulations protect water?" How do their rules apply? Are they adequate? The first step in answering these questions is to evaluate the regulatory frameworks within which programs operate. That is the purpose of this report.

State regulation of oil and natural gas exploration and production activities are approved under state laws that typically include a prohibition against causing harm to the environment. This premise is at the heart of the regulatory process. The regulation of oil and gas field activities is managed best at the state level where regional and local conditions are understood and where regulations can be tailored to fit the needs of the local environment. Hence, the experience, knowledge and information necessary to regulate effectively most commonly rests with state regulatory agencies. Many state agencies use programmatic tools and documents to apply state laws including regulations, formal and informal guidance, field rules, and Best Management Practices (BMPs). They are also equipped to conduct field inspections, enforcement/oversight, and witnessing of specific operations like well construction, testing and plugging.

Regulations alone cannot convey the full measure of a regulatory program. To gain a more complete understanding of how regulatory programs actually function, one has to evaluate the use of state guides, manuals, environmental policy processes, environmental impact statements, requirements established by permit and many other practices. However, that is not the purpose of this study. This study evaluates the language of state oil and gas regulations as they relate to the direct protection of water resources. It is not an evaluation of state programs.

To conduct the study, state oil and gas regulations were reviewed in the following areas: 1) permitting, 2) well construction, 3) hydraulic fracturing, 4) temporary abandonment, 5) well plugging, 6) tanks, 7) pits, and 8) waste handling and spills. Within each area specific sub-areas were included to broaden the scope of this review. For example, in the area of pits, a review was conducted of sub-areas such as pit liners, siting, construction, use, duration and closure. The selection of the twenty-seven states for this study was based upon the last full-year list (2007) of producing states compiled by the U.S. Energy Information Administration.

In the area of well construction, state regulations were evaluated to determine whether the setting of surface casing below ground water zones was required, whether cement circulation on surface casing was also required, and whether the state utilized recognized cement standards. Attachment 3 is a listing of the programmatic areas and sub-areas reviewed.

After evaluation, each state was given the opportunity to review and comment on the findings and to provide updated information concerning their regulations. Thirteen states responded. These responses were incorporated into the study.

One of the most important accomplishments of the study was the development of a regulations reference document (Addendum). This document contains excerpted language from each state's oil and gas regulations related to the programmatic areas included in the study. Hyperlinks to web versions of each state's oil and gas regulations are included as well as some of the forms used by state agencies to implement those regulations. A web enabled version of the study (to be completed by September, 2009) will also contain numerous hyperlinked text segments designed to provide the reader with an easy and effective way to review references and regulations.

Key Messages and Suggested Actions:

Key Message 1: State oil and gas regulations are adequately designed to directly protect water resources through the application of specific programmatic elements such as permitting, well construction, well plugging, and temporary abandonment requirements.

Suggested Action 1: States should review current regulations in several programmatic areas to determine whether or not they meet an appropriate level of specificity (e.g. use of standard cements, plugging materials, pit liners, siting criteria, and tank construction standards etc...)

Key Message 2: Experience suggests that state oil and gas regulations related to well construction are designed to be protective of ground water resources relative to the potential effects of hydraulic fracturing. However, development of Best Management Practices (BMPs) related to hydraulic fracturing would assist states and operators in insuring continued safety of the practice; especially as it relates to hydraulic fracturing of zones in close proximity to ground water, as determined by the regulatory authority.

Suggested Action 2: A study of effective hydraulic fracturing practices should be considered for the purpose of developing (BMPs); which can be adjusted to fit the specific conditions of individual states.

Key Message 3: Many states divide jurisdiction over certain elements of oil and gas regulation between the oil and gas agency and other state water protection agencies. This is particularly evident in the areas of waste handling and spill management.

Suggested Action 3: States with split jurisdiction of programs should insure that formal memorandums of agreement (MOAs) between agencies exist and that these MOAs are maintained to provide more effective and efficient implementation of regulations.

Key Message 4: The state review process conducted by the national non-profit organization State Review of Oil and Natural Gas Environmental Regulations (STRONGER) is an effective tool in assessing the capability of state programs to manage exploration and production waste and in measuring program improvement over time.

Suggested Action 4: The state review process should be continued and, where appropriate, expanded to include state oil and gas programmatic elements not covered by the current state review guidelines.

Key Message 5: The implementation and advancement of electronic data management systems has enhanced regulatory capacity and focus. However, further work is needed in the areas of paper-to-digital data conversion and inclusion of more environmental data.

Suggested Action 5: States should continue to develop and install comprehensive electronic data management systems, convert paper records to electronic formats and incorporate widely scattered environmental data as expeditiously as possible. Federal agencies should provide financial assistance to states in these efforts.

Attachment 2 – GWPC Testimony to the House Committee on Natural Resources, Subcommittee on energy and Mineral Resources, June 4, 2009

Modern Shale Gas Development in the United States: A Primer

EXECUTIVE SUMMARY

Natural gas production from hydrocarbon rich shale formations, known as "shale gas," is one of the most rapidly expanding trends in onshore domestic oil and gas exploration and production today. In some areas, this has included bringing drilling and production to regions of the country that have seen little or no activity in the past. New oil and gas developments bring change to the environmental and socio-economic landscape, particularly in those areas where gas development is a new activity. With these changes have come questions about the nature of shale gas development, the potential environmental impacts, and the ability of the current regulatory structure to deal with this development. Regulators, policy makers, and the public need an objective source of information on which to base answers to these questions and decisions about how to manage the challenges that may accompany shale gas development.

Natural gas plays a key role in meeting U.S. energy demands. Natural gas, coal and oil supply about 85% of the nation's energy, with natural gas supplying about 22% of the total. The percent contribution of natural gas to the U.S. energy supply is expected to remain fairly constant for the next 20 years.

The United States has abundant natural gas resources. The Energy Information Administration estimates that the U.S. has more than 1,744 trillion cubic feet (tcf) of technically recoverable natural gas, including 211 tcf of proved reserves (the discovered, economically recoverable fraction of the original gas-in-place). Technically recoverable unconventional gas (shale gas, tight sands, and coalbed methane) accounts for 60% of the onshore recoverable resource. At the U.S. production rates for 2007, about 19.3 tcf, the current recoverable resource estimate provides enough natural gas to supply the U.S. for the next 90 years. Separate estimates of the shale gas resource extend this supply to 116 years.

Natural gas use is distributed across several sectors of the economy. It is an important energy source for the industrial, commercial and electrical generation sectors, and also serves a vital role in residential heating. Although forecasts vary in their outlook for future demand for natural gas, they all have one thing in common: natural gas will continue to play a significant role in the U.S. energy picture for some time to come.

The lower 48 states have a wide distribution of highly organic shales containing vast resources of natural gas. Already, the fledgling Barnett Shale play in Texas produces 6% of all natural gas produced in the lower 48 States. Three factors have come together in recent years to make shale gas production economically viable: 1) advances in horizontal drilling, 2) advances in hydraulic fracturing, and, perhaps most importantly, 3) rapid increases in natural gas prices in the last several years as a result of significant supply and demand pressures. Analysts have estimated that by 2011 most new reserves growth (50% to 60%, or approximately 3 bcf/day) will come from unconventional shale gas reservoirs. The total recoverable gas resources in four new shale gas plays (the Haynesville, Fayetteville, Marcellus, and Woodford) may be over 550 tcf. Total annual production volumes of 3 to 4 tcf may be sustainable for decades. This potential for production in the known onshore shale basins, coupled with other unconventional gas plays, is predicted to contribute significantly to the U.S.'s domestic energy outlook.

Shale gas is present across much of the lower 48 States. The most active shales to date are the Barnett Shale, the Haynesville/Bossier Shale, the Antrim Shale, the Fayetteville Shale, the Marcellus Shale, and the New Albany Shale. Each of these gas shale basins is different and each has a unique set of exploration criteria and operational challenges. Because of these differences, the development of shale gas resources in each of these areas faces potentially unique opportunities and challenges.

The development and production of oil and gas in the U.S., including shale gas, are regulated under a complex set of federal, state, and local laws that address every aspect of exploration and operation. All of the laws, regulations, and permits that apply to conventional oil and gas exploration and production activities also apply to shale gas development. The U.S. Environmental Protection Agency administers most of the federal laws, although development on federally-owned land is managed primarily by the Bureau of Land Management (part of the Department of the Interior) and the U.S. Forest Service (part of the Department of Agriculture). In addition, each state in which oil and gas is produced has one or more regulatory agencies that permit wells, including their design, location, spacing, operation, and abandonment, as well as environmental activities and discharges, including water management and disposal, waste management and disposal, air emissions, underground injection, wildlife impacts, surface disturbance, and worker health and safety. Many of the federal laws are implemented by the states under agreements and plans approved by the appropriate federal agencies.

A series of federal laws governs most environmental aspects of shale gas development. For example, the Clean Water Act regulates surface discharges of water associated with shale gas drilling and production, as well as storm water runoff from production sites. The Safe Drinking Water Act regulates the underground injection of fluids from shale gas activities. The Clean Air Act limits air emissions from engines, gas processing equipment, and other sources associated with drilling and production. The National Environmental Policy Act (NEPA) requires that exploration and production on federal lands be thoroughly analyzed for environmental impacts. Most of these federal laws have provisions for granting "primacy" to the states (i.e., state agencies implement the programs with federal oversight).

State agencies not only implement and enforce federal laws; they also have their own sets of state laws to administer. The states have broad powers to regulate, permit, and enforce all shale gas development activities—the drilling and fracture of the well, production operations, management and disposal of wastes, and abandonment and plugging of the well. State regulation of the environmental practices related to shale gas development, usually with federal oversight, can more effectively address the regional and state-specific character of the activities, compared to one-sizefits-all regulation at the federal level. Some of these specific factors include: geology, hydrology, climate, topography, industry characteristics, development history, state legal structures, population density, and local economics. State laws often add additional levels of environmental protection and requirements. Also, several states have their own versions of the federal NEPA law, requiring environmental assessments and reviews at the state level and extending those reviews beyond federal lands to state and private lands.

A key element in the emergence of shale gas production has been the refinement of cost-effective horizontal drilling and hydraulic fracturing technologies. These two processes, along with the implementation of protective environmental management practices, have allowed shale gas development to move into areas that previously would have been inaccessible. Accordingly, it is important to understand the technologies and practices employed by the industry and their ability to prevent or minimize the potential effects of shale gas development on human health and the environment and on the quality of life in the communities in which shale gas production is located.

Modern shale gas development is a technologically driven process for the production of natural gas resources. Currently, the drilling and completion of shale gas wells includes both vertical and horizontal wells. In both kinds of wells, casing and cement are installed to protect fresh and treatable water aquifers. The emerging shale gas basins are expected to follow a trend similar to the Barnett Shale play with increasing numbers of horizontal wells as the plays mature. Shale gas operators are increasingly relying on horizontal well completions to optimize recovery and well economics. Horizontal drilling provides more exposure to a formation than does a vertical well. This increase in reservoir exposure creates a number of advantages over vertical wells drilling. Six to eight horizontal wells drilled from only one well pad can access the same reservoir volume as sixteen vertical wells. Using multi-well pads can also significantly reduce the overall number of well pads, access roads, pipeline routes, and production facilities required, thus minimizing habitat disturbance, impacts to the public, and the overall environmental footprint.

The other technological key to the economic recovery of shale gas is hydraulic fracturing, which involves the pumping of a fracturing fluid under high pressure into a shale formation to generate fractures or cracks in the target rock formation. This allows the natural gas to flow out of the shale to the well in economic quantities. Ground water is protected during the shale gas fracturing process by a combination of the casing and cement that is installed when the well is drilled and the thousands of feet of rock between the fracture zone and any fresh or treatable aquifers. For shale gas development, fracture fluids are primarily water based fluids mixed with additives that help the water to carry sand proppant into the fractures. Water and sand make up over 98% of the fracture fluid, with the rest consisting of various chemical additives that improve the effectiveness of the fracture job. Each hydraulic fracture treatment is a highly controlled process designed to the specific conditions of the target formation.

The amount of water needed to drill and fracture a horizontal shale gas well generally ranges from about 2 million to 4 million gallons, depending on the basin and formation characteristics. While these volumes may seem very large, they are small by comparison to some other uses of water, such as agriculture, electric power generation, and municipalities, and generally represent a small percentage of the total water resource use in each shale gas area. Calculations indicate that water use for shale gas development will range from less than 0.1% to 0.8% of total water use by basin. Because the development of shale gas is new in some areas, these water needs may still challenge supplies and infrastructure. As operators look to develop new shale gas plays, communication with local water planning agencies, state agencies, and regional water basin commissions can help operators and communities to coexist and effectively manage local water resources. One key to the successful development of shale gas is the identification of water supplies capable of meeting the needs of a development company for drilling and fracturing water without interfering with community needs. While a variety of options exist, the conditions of obtaining water are complex and vary by region.

After the drilling and fracturing of the well are completed, water is produced along with the natural gas. Some of this water is returned fracture fluid and some is natural formation water. Regardless of the source, these produced waters that move back through the wellhead with the gas represent a stream that must be managed. States, local governments, and shale gas operators seek to manage produced water in a way that protects surface and ground water resources and, if possible, reduces future demands for fresh water. By pursuing the pollution prevention hierarchy of "Reduce, Re-use, and Recycle" these groups are examining both traditional and innovative approaches to managing shale gas produced water. This water is currently managed through a variety of mechanisms, including underground injection, treatment and discharge, and recycling. New water treatment technologies and new applications of existing technologies are being developed and used to treat shale gas produced water for reuse in a variety of applications. This allows shale gas-associated produced water to be viewed as a potential resource in its own right.

Some soils and geologic formations contain low levels of naturally occurring radioactive material (NORM). When NORM is brought to the surface during shale gas drilling and production operations, it remains in the rock pieces of the drill cuttings, remains in solution with produced water, or, under certain conditions, precipitates out in scales or sludges. The radiation from this NORM is weak and cannot penetrate dense materials such as the steel used in pipes and tanks.

Because the general public does not come into contact with gas field equipment for extended periods, there is very little exposure risk from gas field NORM. To protect gas field workers, OSHA requires employers to evaluate radiation hazards, post caution signs and provide personal protection equipment when radiation doses could exceed regulatory standards. Although regulations vary by state, in general, if NORM concentrations are less than regulatory standards, operators are allowed to dispose of the material by methods approved for standard gas field waste. Conversely, if NORM concentrations are above regulatory limits, the material must be disposed of at a licensed facility. These regulations, standards, and practices ensure that shale gas operations present negligible risk to the general public and to workers with respect to potential NORM exposure.

Although natural gas offers a number of environmental benefits over other sources of energy, particularly other fossil fuels, some air emissions commonly occur during exploration and production activities. Emissions may include NO_x, volatile organic compounds, particulate matter, SO_2, and methane. EPA sets standards, monitors the ambient air across the U.S., and has an active enforcement program to control air emissions from all sources, including the shale gas industry. Gas field emissions are controlled and minimized through a combination of government regulation and voluntary avoidance, minimization, and mitigation strategies.

The primary differences between modern shale gas development and conventional natural gas development are the extensive uses of horizontal drilling and high-volume hydraulic fracturing. The use of horizontal drilling has not introduced any new environmental concerns. In fact, the reduced number of horizontal wells needed coupled with the ability to drill multiple wells from a single pad has significantly reduced surface disturbances and associated impacts to wildlife, dust, noise, and traffic. Where shale gas development has intersected with urban and industrial settings, regulators and industry have developed special practices to alleviate nuisance impacts, impacts to sensitive environmental resources, and interference with existing businesses. Hydraulic fracturing has been a key technology in making shale gas an affordable addition to the Nation's energy supply, and the technology has proved to be an effective stimulation technique. While some challenges exist with water availability and water management, innovative regional solutions are emerging that allow shale gas development to continue while ensuring that the water needs of other users are not affected and that surface and ground water quality is protected. Taken together, state and federal requirements along with the technologies and practices developed by industry serve to reduce environmental impacts from shale gas operations.

Ohio Department of Natural Resources

TED STRICKLAND, GOVERNOR
SEAN D. LOGAN, DIRECTOR

John F. Husted, Chief
Division of Mineral Resources Management
2045 Morse Road, Building H-3
Columbus, OH 43229-6693
Phone: (614) 265-6633 Fax: (614) 265-7999

May 27, 2009

Mike Paque
Executive Director
Ground Water Protection Council
13309 North MacArthur Boulevard
Oklahoma City, Oklahoma 73142

Dear Mike:

In recent months, the Ohio Department of Natural Resources, Division of Mineral Resources Management (DMRM) has become aware of website and media releases reporting that the State of Ohio has documented cases of ground water contamination caused by the standard industry practice of hydraulic fracturing. Such reports are not accurate. For example, some articles inaccurately portrayed hydraulic fracturing as the cause of a natural gas incident in Bainbridge Township of Geauga County that resulted in an in-home explosion in December 2007. This portrayal is not consistent with the findings or conclusions of the DMRM.

DMRM completed a thorough investigation into the cause of a natural gas invasion into fresh water aquifers in Bainbridge Township. The DMRM investigation found that this incident was caused by a defective primary cement job on the production casing, which was further complicated by operator error. As a consequence of this finding, the operator corrected the construction problem by completing remedial cementing operations. The findings and conclusions of this investigation are available on the web at http://www.dnr.state.oh.us/bainbridge/tabid/20484/default.aspx.

While an explosion significantly damaged one house, the investigation did not find any evidence to support the claim "that pressure caused by hydraulic fracturing pushed the gas...through a system of cracks into the ground water aquifer" as reported by some media accounts. In actuality, the team of geologists who completed the evaluation of the gas invasion incident in Bainbridge Township concluded that the problem would have occurred even if the well had never been stimulated by hydraulic fracturing.

After 25 years of investigating citizen complaints of contamination, DMRM geologists have not documented a single incident involving contamination of ground water attributed to hydraulic fracturing. Over this time, the Ohio DMRM has consistently taken decisive action to address oil and gas exploration and production practices that have caused documented incidents of ground water contamination. The DMRM has initiated amendments to statutes and rules, designed permit conditions, refined standards

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operating procedures, and developed best management practices to improve protection of ground water resources. These actions resulted in substantive changes including:

1. elimination of tens of thousands of earthen pits for produced water storage;
2. development of a model Class II brine injection well program;
3. development of technical standards for synthetic liners used in pits during drilling operations;
4. tighter standards for construction and mechanical integrity testing for annular disposal wells;
5. detailed plugging regulations; and,
6. establishment of an orphaned well plugging program funded by a severance tax on oil and gas production.

The Ohio DMRM will continue to assign the highest priority to improving protection of water resources and public health and safety.

In conclusion, the Ohio DMRM has not identified hydraulic fracturing as a significant threat to ground water resources.

Sincerely,

Scott R. Kell

Scott R. Kell, Deputy Chief

SRK/csc

Enclosure

cc: Cathryn Loucas, Deputy Director, ODNR
Mike Shelton, Chief, Legislative Services, ODNR
John Husted, Chief, DMRM

Pennsylvania Department of Environmental Protection

Rachel Carson State Office Building
P.O. Box 8555
Harrisburg, PA 17105-8555

June 1, 2009

Bureau of Watershed Management 717-772-4048

Michael Paque, Executive Director
Ground Water Protection Council
13308 North MacArthur Boulevard
Oklahoma City, OK 73142

Dear Mr. Paque:

I am the program manager for Pennsylvania's Ground Water Protection Program in the Pennsylvania Department of Environmental Protection (DEP). I have been concerned about press reports stating extensive groundwater pollution and contamination of underground sources of drinking water in Pennsylvania, as a result of hydraulic fracturing to stimulate gas production from deep, gas bearing rock formations. DEP has not concluded that the activity of hydraulic fracturing of these formations has caused wide-spread groundwater contamination.

After review of DEP's complaint database and interviews with regional staff that investigate groundwater contamination related to oil and gas activities, no groundwater pollution or disruption of underground sources of drinking water has been attributed to hydraulic fracturing of deep gas formations. All investigated cases that have found pollution, which are less then 80 in over 15 years of records, have been primarily related to physical drilling through the aquifers, improper design or setting of upper and middle well casings, or operator negligence.

If you have any questions or concerns, you may contact me by e-mail at josless@state.pa.us or by telephone at 717-772-4048.

Sincerely,

Joseph J. Lee, Jr., P.G., chief
Source Protection Section
Division of Water Use Planning

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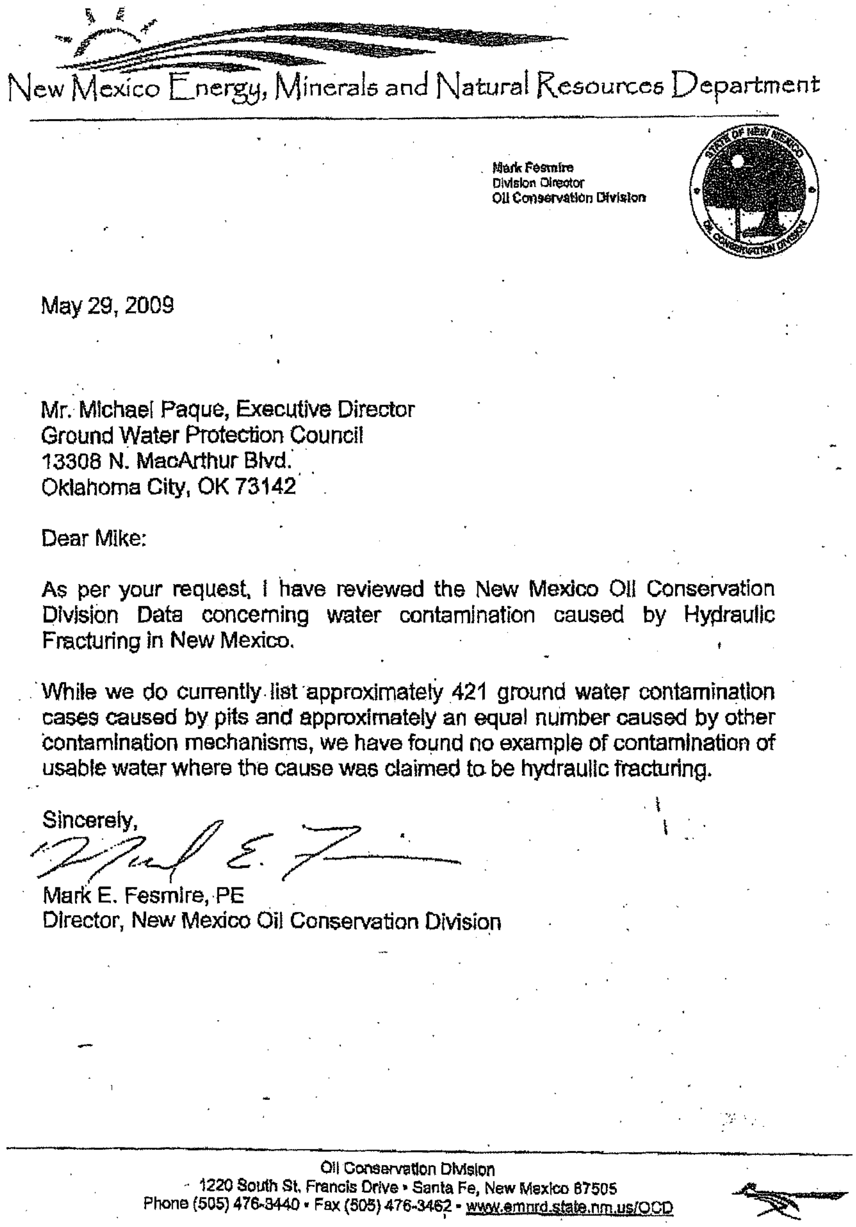


New Mexico Energy, Minerals and Natural Resources Department

Mark Fesmire
Division Director
Oil Conservation Division

May 29, 2009

Mr. Michael Paque, Executive Director
Ground Water Protection Council
13308 N. MacArthur Blvd.
Oklahoma City, OK 73142

Dear Mike:

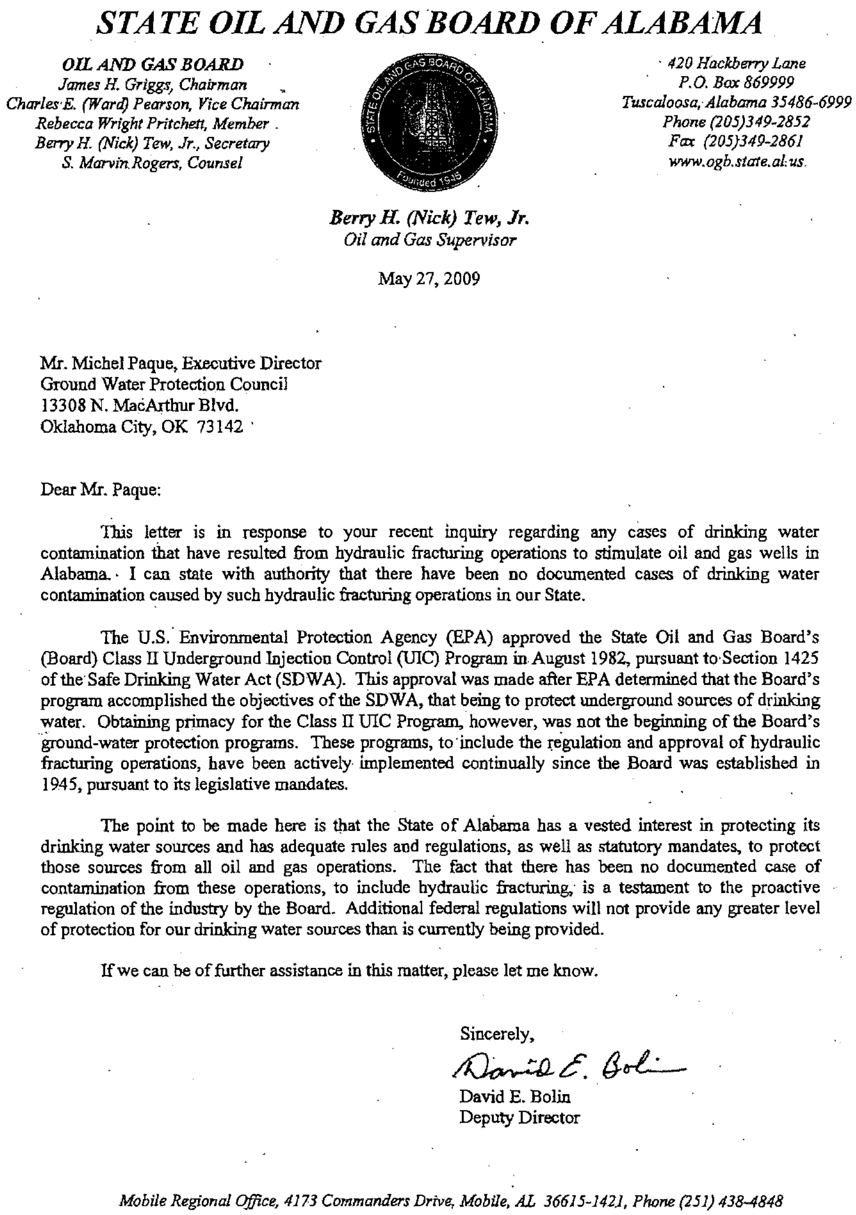
As per your request, I have reviewed the New Mexico Oil Conservation Division Data concerning water contamination caused by Hydraulic Fracturing in New Mexico.

While we do currently list approximately 421 ground water contamination cases caused by pits and approximately an equal number caused by other contamination mechanisms, we have found no example of contamination of usable water where the cause was claimed to be hydraulic fracturing.

Sincerely,

Mark E. Fesmire, PE
Director, New Mexico Oil Conservation Division

Oil Conservation Division
1220 South St. Francis Drive • Santa Fe, New Mexico 87505
Phone (505) 476-3440 • Fax (505) 476-3462 • www.emnrd.state.nm.us/OCD



STATE OIL AND GAS BOARD OF ALABAMA

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Founded 1945

Berry H. (Nick) Tew, Jr.
Oil and Gas Supervisor

May 27, 2009

Mr. Michel Paque, Executive Director
Ground Water Protection Council
13308 N. MacArthur Blvd.
Oklahoma City, OK 73142

Dear Mr. Paque:

This letter is in response to your recent inquiry regarding any cases of drinking water contamination that have resulted from hydraulic fracturing operations to stimulate oil and gas wells in Alabama. I can state with authority that there have been no documented cases of drinking water contamination caused by such hydraulic fracturing operations in our State.

The U.S. Environmental Protection Agency (EPA) approved the State Oil and Gas Board's (Board) Class II Underground Injection Control (UIC) Program in August 1982, pursuant to Section 1425 of the Safe Drinking Water Act (SDWA). This approval was made after EPA determined that the Board's program accomplished the objectives of the SDWA, that being to protect underground sources of drinking water. Obtaining primacy for the Class II UIC Program, however, was not the beginning of the Board's ground-water protection programs. These programs, to include the regulation and approval of hydraulic fracturing operations, have been actively implemented continually since the Board was established in 1945, pursuant to its legislative mandates.

The point to be made here is that the State of Alabama has a vested interest in protecting its drinking water sources and has adequate rules and regulations, as well as statutory mandates, to protect those sources from all oil and gas operations. The fact that there has been no documented case of contamination from these operations, to include hydraulic fracturing, is a testament to the proactive regulation of the industry by the Board. Additional federal regulations will not provide any greater level of protection for our drinking water sources than is currently being provided.

If we can be of further assistance in this matter, please let me know.

Sincerely,

David E. Bolin

David E. Bolin
Deputy Director

Mobile Regional Office, 4173 Commanders Drive, Mobile, AL 36615-1421, Phone (251) 438-4848

RAILROAD COMMISSION OF TEXAS
CHAIRMAN VICTOR G. CARRILLO

May 29, 2009

Mike Paque, Executive Director
Ground Water Protection Agency
13308 N. MacArthur Blvd.
Oklahoma City, OK 73142

Re: Hydraulic Fracturing of Gas Wells in Texas

Dear Mr. Paque:

I am pleased that representatives of the Ground Water Protection Council will be appearing before the U.S. House Committee on Natural Resources next week on the issue of hydraulic fracturing. I was asked to participate but had a longstanding commitment to tour energy projects in Canada that prevented me from personally participating.

I sincerely hope that you will clear up the misconception that there are "thousands" of contamination cases in Texas and other states resulting from hydraulic fracturing. The Railroad Commission of Texas is the chief regulatory agency over oil and gas activities in this state. Though hydraulic fracturing has been used for over 50 years in Texas, our records do not indicate a single documented contamination case associated with hydraulic fracturing.

The Texas Groundwater Protection Committee (TGPC) tracks groundwater pollution in Texas. All Texas water protection agencies, including the Railroad Commission, are members. Each year, the TGPC publishes a Joint Groundwater Monitoring and Contamination Report, which can be found at http://www.tceq.state.tx.us/comm_exec/forms_pubs/pubs/sfr/056_07_index.html. The 2007 report cites a total of 354 active groundwater cases attributed to oil and gas activity – this in a state with over 255,000 active oil and gas wells. The majority of these cases are associated with previous practices that are no longer allowed, or result from activity now prohibited by our existing regulations. A few cases were due to blowouts that primarily occur during drilling activity. *Not one of these cases was caused by hydraulic fracturing activity.*

Hydraulic fracturing plays a key role in the development of virtually all unconventional gas resources in Texas. As of this year, over 11,000 gas wells have been completed (and hydraulically fractured) in the Barnett Shale reservoir, one of the nation's most active and largest natural gas fields. Since 2000, over five trillion cubic feet of gas has been produced from this one reservoir and the Barnett Shale production currently contributes over 20% of Texas' total natural gas production. While the volume of gas-in-place in the Barnett Shale is estimated to be over 27 trillion cubic feet, recovery of the gas is difficult because of the shale's low permeability. The remarkable success of the Barnett Shale results in large part from the use of horizontal drilling coupled with hydraulic fracturing. Even with this intense activity, there are no known instances of ongoing groundwater contamination in the Barnett Shale play.

P.O. Box 12967 ★ Austin, Texas 78711-2967 ★ Phone (512) 463-7131 ★ Fax (512) 463-7161

Regulation of oil and gas exploration and production activities, including hydraulic fracturing, has traditionally been the province of the states. Most oil and gas producing state have had effective programs in place for decades. Regulating hydraulic fracturing as underground injection under the federal Safe Drinking Water Act would impose significant additional costs and regulatory burdens and could ultimately reverse the significant U.S. domestic unconventional gas reserve additions of recent years – harming domestic energy security. I urge the U.S. Congress to leave the regulatory authority over hydraulic fraturing and other oil and gas activities where it belongs – at the state level.

Sincerely,

Victor G. Carrillo, Chairman
Railroad Commission of Texas

cc: Commissioner Michael Williams
Commissioner Elizabeth Ames Jones
John J. Tintera, Executive Director

Natural Gas Drilling: Public Health and Environmental Impacts

Testimony of
Michael L. Krancer
Acting-Secretary
Commonwealth of Pennsylvania
Department of Environmental Protection

Before the United States Senate
Environment and Public Works Committee
April 12, 2011

Members of the Committee, thank you for the opportunity to provide testimony on behalf of the Commonwealth of Pennsylvania, Department of Environmental Protection.

The potential of the Marcellus Shale play has captured the world's attention. Indeed, not since Edwin Drake drilled North America's first commercial oil well in 1859 have so many focused their attention on Pennsylvania as an opportunity for oil and gas development. Increased well drilling has also brought with it unfounded skepticism about Pennsylvania's ability to properly oversee the oil and gas industry.

I say unfounded because just last year the head of EPA's Drinking Water Program said publically that "I have no information that states aren't doing a good job already [regulating fracking]." That is certainly the case for Pennsylvania. Also, our regulatory program was recently evaluated by the independent, multi-stakeholder State Review of Oil and Natural Gas Environmental Regulations organization (STRONGER) and received positive marks. According to STRONGER, "the Pennsylvania program is, over all, well-managed, professional and meeting its program objectives." I would go beyond that and say that Pennsylvania has done an exceptional job managing the new challenges that shale gas development presents while allowing our citizens to enjoy the enormous benefits created by this industry.

Our ability to unlock the huge energy source contained in unconventional shale formations will transform Pennsylvania into an energy exporter and move our nation toward energy independence. In addition, we are looking at an economic transformation. We have already seen tens of thousands of new jobs here in Pennsylvania from the industry itself as well as from new industries spawned to support it. These are good paying career jobs in many fields. And that is just the start. There will be hundreds of thousands more good paying skilled and unskilled jobs in a variety of sectors. While interest in the economic possibilities of the Marcellus is high, Pennsylvania will see that its environment and the health and safety of its citizens is protected.

Pennsylvania regulates oil and gas well operations under several statutes including the Oil and Gas Act, the Clean Streams Law, the Dam Safety and Encroachments Act and the Solid Waste Management Act. As described in more detail below, this network of laws and their associated regulations provides the Department of Environmental Protection

(DEP) with the tools it needs to comprehensively regulate everything associated with oil and gas development - from locating the well site, site preparation, drilling the well, fresh water withdrawals and water storage, wastewater management, and site restoration.

Simply put, because of our long history of oil and gas development and comprehensive regulatory structure, Pennsylvania does not need federal intervention to ensure an appropriate balance between resource development and environmental protection is struck.

Well Site Location

The Oil and Gas Act (58 P.S. §§ 601.101 *et. seq*) is the primary law governing well drilling in Pennsylvania. With the exception of wells drilled through workable coal seams, there are no spacing requirements for Marcellus Shale wells. Although spacing restrictions do not generally apply, the Oil and Gas Act, the Dam Safety and Encroachments Act (32 P.S. §§ 693.1 *et. seq*) and the Clean Streams Law (35 P.S. §§ 691.1 *et seq*) regulate where well sites may be located and how the site should be constructed.

Section 601.205 of the Oil and Gas Act prohibits operators from developing a well site within 100 feet of any stream, spring or body of water that is identified on a topo map (small intermittent or head water streams are not always identified). In addition, the site may not be located within 200 feet of buildings or water wells. The department may waive these restrictions if additional protective measures are included as conditions to the well permit. Typical conditions include additional erosion and sediment control measures and measures to deal with the additional fresh water that will be encountered while drilling.

25 Pa. Code Chapter 105 (the Dam Safety and Encroachment regulations) requires well operators to obtain an encroachment permit if a well site or other support facility (such as an access road or water withdrawal pad) is located within a FEMA designated floodway. If FEMA has not designated a floodway (as can be the case for small streams), the operator must obtain a permit if the facility will be within 50 feet of a stream. For Chapter 105 purposes, a stream is anything that has a defined bed and bank – this is much more inclusive than the Oil and Gas Act provisions.

Finally, locating well sites within a floodplain may be regulated by municipalities through the Flood Plain Management Act. Certain ordinances promulgated through this statute are not preempted by the Oil and Gas Act. 58 P.S. § 601.602.

Site Development

Developing a well site outside the location restrictions of the Oil and Gas Act and the Dam Safety and Encroachments Act is regulated under the Clean Streams Law through the Department's erosion and sediment control program.

Stormwater runoff is the leading cause of stream impairment in Pennsylvania. To address this problem, DEP has developed a comprehensive stormwater management program. Pursuant to 25 Pa. Code Chapter 102, all earth disturbance activities must employ "best management practices" like silt fences and road side culverts to control erosion and manage stormwater. Relative to building sites in floodplains, pits and impoundments used to store waste material may not be used if the bottom of the pit will be within 20 inches of the ground water table. 25 Pa. Code § 78.56. In floodplains, the ground water table will be close to the surface and therefore, drilling wastes would need to be contained in tanks if a pit could not be used.

If well site construction will disturb more than 5,000 square feet or has the potential to discharge sediment to High Quality or Exceptional Value waters (so classified pursuant to 25 Pa. Code Chapter 93), the operator must develop and implement an erosion and sediment control plan. This E&S plan must be kept on site for review by DEP. If development of the well site, access roads and other related facilities will disturb 5 or more acres, the operator must obtain an erosion and sediment control permit before the site can be developed.

Well Drilling

Drilling any well – even a water well – has the potential to impact fresh groundwater. While this potential may exist, such an impact is not acceptable. Protecting groundwater supplies is of utmost importance and the Oil and Gas Act is particularly strict in this regard. If a well operator impacts a water supply (by pollution or diminution), they *must* restore or replace it and pay for any increased costs of maintaining or operating the replacement supply. 58 P.S. § 601.208.

In fact, if an oil or gas well is drilled within 1,000 feet of a water supply and the water supply becomes polluted within 6 months of drilling, the operator is *presumed* to have caused the pollution unless they took a water sample that demonstrates the pollution was present before the oil or gas well was drilled. 58 P.S. § 601.208(c). Needless to say, taking a pre-drilling water sample from all supplies within 1000 feet of a gas well should be a standard business practice.

Of course, the goal is to avoid groundwater impacts in the first place. To that end, DEP recently promulgated new regulations that significantly strengthen our well construction standards. These new regulations accomplish five things.

First, the regulations will establish more stringent well construction standards for all new wells drilled in Pennsylvania. Second, the regulations impose new requirements on operators to inspect existing wells and report their findings to the Department. Third, the regulations codify existing caselaw on water supply replacement requirements and clearly describe an operator's responsibilities if they contaminate or diminish a water supply. Fourth, the regulations impose a duty on operators to investigate complaints of gas migration and to mitigate any hazards found in the course of the investigation. Finally, the regulations require reporting of chemicals used to hydraulically fracture wells.

Below is a brief description of the significant new requirements in 25 Pa. Code Chapter 78.

I. New Well Drilling

Properly cementing and casing a well is critical to preventing gas migration. Prior to drilling a well, operators will now be required to develop a casing and cementing plan that shows how the well will be drilled and completed. Use of centralizers (which keep the casing centered in the well bore) must be used at prescribed locations to insure that cement is evenly distributed between the casing and the well bore. Cement meeting ASTM criteria for oil and gas wells must be used. Documentation of the cement quality and cementing practices used at the well must be available for Department inspection.

When cementing a well, if cement is not returned to the surface the operator must install a second string of casing for an added layer of protection. If cement is returned to the surface and the operator intends to only use surface casing (Marcellus operators typically use surface, intermediate and production casing), the operator must demonstrate that any gas, oil and produced fluids cannot leave the well bore.

Used or welded casing must be pressure tested. Casing strings attached to heavy duty blow-out preventers (such as Marcellus intermediate casing) must also be pressure tested.

II. Existing Wells

Operators must inspect all of their wells quarterly and report the findings of the inspections to the Department annually. If defective casing, evidence of leaks, or if excessive pressure within the well bore is discovered, the operator must immediately notify the Department and take corrective action.

III. Water Supply Replacement

The Oil and Gas Act requires any operator who contaminates or diminishes a water supply to restore or replace the supply with one that is adequate in quantity and quality for the purposes served. Case law on these requirements has defined when an operator must provide compensation for increased operation and maintenance costs (when costs are more than a deminimus amount) and for what duration (in perpetuity). The regulations codify these and other relevant holdings to clearly describe the operator's responsibility.

IV. Gas Migration Response

The new regulations impose a duty on operators to immediately investigate a gas migration complaint and to notify the Department if they receive such a complaint. If natural gas is found at elevated levels (10% of the lower explosive limit) the operator must immediately notify emergency responders and initiate mitigation measures (including advisories and controlling access to the area).

V. Reporting Requirements

The practice of hydraulic fracturing has drawn considerable attention recently. One of the primary concerns involves the chemicals used during the process. DEP's new regulations require operators to disclose the chemical additives and the hazardous constituents of those additives on a well by well basis. While DEP has never observed any evidence that hydraulic fracturing has directly contaminated fresh groundwater despite tens of thousands of wells being "fraced" over the past several decades, mandating public disclosure of the chemicals used in the process should end much of the controversy surrounding the subject.

Water Withdrawal

While the volume of water to frac a Marcellus well is greater than the amount required to frac traditional wells in Pennsylvania, the Marcellus industry's use of water is miniscule in comparison with other energy sources and other sources in general. Marcellus fracing is the smallest major user in Pennsylvania using only 0.2% of the daily water withdrawn which ranks it ninth of the top nine water users in the state. Marcellus drilling uses only 1.9 million gallons per day (MGD). This is in stark contrast to power plants which use 6.43 *billion* gallons per day (BGD). Other major uses include public water suppliers (1.42 BGD); industrial users (770 MGD); aquaculture (524 MGD); private water wells (152 MGD); mining (95.7 MGD); livestock (61.8 MGD); and irrigation (24.3 MGD). Thus, shale gas drilling is a fabulously efficient energy production source measured as a function of water usage.

Still, withdrawing more than 5 million gallons per well from the headwaters of the Commonwealth's most pristine streams has the potential to impair water quality through diminished stream flows. To prevent impacts from occurring, Marcellus operators can only withdraw water pursuant to an approved water management plan.

There are three entities charged with protecting water quality by managing water withdrawals in Pennsylvania - DEP, the Susquehanna River Basin Commission and the Delaware River Basin Commission. The two River Basin Commissions were formed by a compact between the federal government, Pennsylvania and neighboring states within the respective watersheds. If a Marcellus well is drilled within the Susquehanna or Delaware River watershed, DEP and Commission approval of the operator's water management plan must be obtained before construction of the well site can begin. If the well is located outside those two river basins, only DEP approval is necessary.

The water management plan is based on low flow conditions and describes where water will be withdrawn how much water will be needed and the amount of water that will be taken at any one time. Evaluation of the plan involves looking both upstream and downstream to assess cumulative impacts, taking into account all other withdrawals and discharges and their impact on the resource, particularly during low flow periods.

Generally speaking, if the water withdrawal is less than 10 percent of the natural or continuously augmented 7-day, 10-year low flow (Q7-10) of the stream or river, a passby (a restriction on the ability to take water during low flow conditions) will not be required. Q7-10 is the lowest average, consecutive 7-day flow that would occur with a frequency or recurrence interval of one in ten years. A 10-year low flow event has a 10 percent chance of occurring in any one year. Accepted hydrologic practices must be used to determine the Q7-10 flow.[1]

Once approved, the plan is valid for each location for five years. Although the Commonwealth has ample water resources, operators will need to cooperate to make sure that access to water is available as more and more plans are submitted for headwater streams.

Water and Wastewater Storage

Once an operator gets the water needed to frac a well, the question becomes where to put it? Even more important, where to put the wastewater that is returned to the surface (called flowback)? A new development with Marcellus wells is the advent of centralized impoundments. Unlike pits located immediately adjacent to the well, centralized impoundments use dam like structures to hold enough water to service multiple wells over an extended period of time. These impoundments can store freshwater, and more increasingly, flowback from a frac job.

Under DEP's dam safety regulations, small freshwater impoundments – similar to a farmer's pond - do not need a permit. However, Marcellus impoundments can hold over 15 million gallons and if they store wastewater, must be permitted and constructed according to DEP standards. Key standards include a two impervious 40 mil liners with a leak detection zone and groundwater monitoring wells around the impoundment. Impoundments located where a breach could threaten public safety must undergo a much more stringent engineering review.

Wastewater Management

The most significant issue facing Marcellus operators today is wastewater treatment and disposal. Operators report that approximately 15% of the water used frac a well is returned to the surface during the initial flowback period. The Department has seen an increase in reuse of this wastewater – industry wide approximately 80% of the flowback is used on another frac job. Thus, the total volume of wastewater that must be disposed is a small fraction of the volume needed to frac the well.

Still, flowback from Marcellus frac jobs contain pollutants of concern – particularly high levels of dissolved salts. Indeed, flowback water is several times saltier than sea water. Thus, Total Dissolved Solids (TDS) represent a growing concern for the Commonwealth's waterways and the Department has developed a proactive strategy to address this concern before widespread impacts are felt.

The best solution for disposing of high TDS wastewater is deep well injection. Unfortunately, the best geology in Pennsylvania for this method of waste disposal is being used for gas storage. Exploration for new injection sites is ongoing but not commercially available yet.

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[1] Policy No. 2003-01 Guidelines For Using and Determining Passby Flows and Conservation Releases For Surface-Water and Ground-Water Withdrawal Approvals, November 8, 2002.

Therefore, the current preference for flowback water disposal is through existing DEP approved wastewater treatment plants. These plants typically do not the have technology necessary to remove TDS from the effluent and instead rely on dilution. The DEP's recently promulgated Chapter 95 regulations completely address the cumulative impacts of oil and gas wastewater discharges.

This new rule is the first of its kind in the country and limits the discharge of TDS from new or expanded facilities that take oil and gas wastewater to drinking water standards. This means that new discharges cannot exceed 250 mg/l for chlorides and that drinking water supplies will never be impaired because of oil and gas drilling. The process of eliminating the TDS will also remove radium – which has been the subject of recent articles. Thus, in addition to reducing the contaminants discharged to our streams, the new Chapter 95 rule will increase the use or recycled water, promote the development of alternative forms of disposal and perhaps promote the use of alternative sources of fracing fluid.

Drinking Water Protection.

As I recently outlined in my April 6, 2011 letter to EPA Region III Administrator Garvin, over the past three years the Commonwealth has been very pro-active in protecting potential sources of drinking water. In addition to the Chapter 95 TDS regulations discussed above there are other measures being implemented. DEP recently announced the results of our in-stream water quality monitoring for radioactive material in seven of the Commonwealth's rivers. All samples showed levels at or below the normal naturally occurring background levels of gross alpha and gross beta radiation. Those tests were conducted in November and December of 2010 at stations downstream of wastewater treatment plants that accept flowback and production water from Marcellus Shale drilling. These sampling stations were installed last fall specifically for the purpose of monitoring stream quality for potential impacts from unconventional gas drilling operations. The raw water river samples were collected above public water suppliers' intakes where the water receives further treatment.

The seven river testing stations are located at the Monongahela at Charleroi in Washington County; South Fork Ten Mile Creek in Greene County; Conemaugh in Indiana County; Allegheny at Kennerdell in Venango County; Beaver in Beaver County; Tioga in Tioga County; and the West Branch of the Susquehanna in Lycoming County. These stations were chosen because of their proximity to public water supply intakes and at the time, were located downstream of facilities permitted to or proposing to discharge oil and gas wastewater. Future monitoring will include monthly sampling at the Monongahela; South Fork Ten Mile; Allegheny; and Beaver sites and every other month at the remaining three sites. Moreover, gross alpha and gross beta testing was added to a second water quality network station on the Monongahela, in March 2011. This site is further downstream in Allegheny County. All of the results will be frequently evaluated and available to the public via EPA's Modernized STORET database.

There is more. Pennsylvania DEP has taken measures to have additional monitoring of finished water at 14 public water supplies with surface water intakes downstream from wastewater treatment facilities that accept Marcellus wastewater. On March 11, 2011, under Pennsylvania regulation 25 *Pa Code* §109.302, we directed a letter to public water suppliers that have surface water intakes located downstream of one or more facilities that are accepting Marcellus wastewater to immediately conduct testing of radionuclides (i.e., radioactivity) and other parameters including TDS, pH, alkalinity, chloride, sulfate and bromide. A copy of that letter and the list of recipients is enclosed.

In addition, Pennsylvania DEP, on March 18, 2011, under Pennsylvania regulation 25 *Pa Code* §92a.61(g), sent letters to 25 Publicly Owned Treatment Works and Centralized Waste Treatment facilities that currently accept this wastewater calling for immediate twice monthly effluent monitoring for radionuclides and other parameters including TDS, pH, alkalinity, chloride, sulfate, bromide, gross alpha, radium 226 & 228, and uranium.

A copy of my letter of April 6, 2011 and its enclosures are attached hereto and incorporated into this testimony.

Conclusion

The Marcellus Shale play along with other domestic unconventional resources can transform world energy markets. This potential will only be realized by avoiding the mistakes of the past. I believe that Pennsylvania will prove that the balance between environmental protection and the development of this world class resource is possible.

MARCELLUS
SHALE COALITION

Statement of the Marcellus Shale Coalition
Kathryn Z. Klaber
President & Executive Director

Before the U.S. Senate Environment and Public Works Committee
April 12, 2011

The Marcellus Shale Coalition (MSC) is a multi-state organization, founded in 2008 to advance the responsible development of natural gas from the Marcellus Shale geological formation that underlies a number of states, including Pennsylvania, New York, Ohio, West Virginia, and Maryland. Working with state and federal regulators, elected officials and the general public, the MSC seeks to educate, engage and promote natural gas as a clean, job-creating resource with tremendous economic and environmental benefits. The members of the coalition are dedicated to developing this resource safely and efficiently.

Thank you for the opportunity to submit this testimony regarding impacts of Marcellus Shale Drilling. In terms of "impacts" there are innumerable positive energy and environmental impacts that the responsible development of the Marcellus brings. In 2010, we again commissioned economists from the Penn State College of Earth and Mineral Sciences Department of Energy and Mineral Engineering to examine the economic impact of the Marcellus Shale on Pennsylvania, resulting in the release of *The Economic Impacts of the Pennsylvania Marcellus Natural Gas Play: An Update*, in the spring of 2010. The study shows responsible development of natural gas from the Marcellus shale formation is having a significant impact on the Commonwealth that is being felt locally.

The energy impact of production from the Marcellus and other shale plays in the United States cannot be understated. According to published reports, the U.S. Department of Energy has recently doubled its estimate of available supply of natural gas due to the Marcellus and other shale plays. As a result, the wellhead price of natural gas is expected to be fairly stable through at least the next decade and at lower levels than estimated just last year. Some of the impacts will be felt by natural gas and electric utility customers. The Department of Energy estimates that the price per kilowatt hour of electricity will actually decrease due to the increased supply of natural gas.

According to the study by researchers at Penn State, at full development, the Marcellus will be the second largest natural gas field in the entire world. In terms of production of natural gas here in the United States, Pennsylvania will be second only to Texas. The study estimated 2010 production at 1 BCFE (billion cubic feet equivalent) per day, and by 2020, that number is estimated at 13.5 BCFE per day. In the coming years this activity will make Pennsylvania a net exporter of natural gas, meaning that the Commonwealth will be natural gas independent.

According to the Pennsylvania Department of Environmental Protection, nearly 3,000 Marcellus wells have been drilled in Pennsylvania since 2005. Preliminary information indicates that production from the wells is exceeding expectations. According to the study by researchers at Penn State, we can expect to see 3500 wells per year drilled in Pennsylvania by 2020. To put this figure in context we should note that more than 350,000 oil and gas wells have been drilled in Pennsylvania to date.

The responsible development of natural gas from the Marcellus has a tremendous impact on the local and state economies. Each Marcellus well requires an investment of about $4 million, while each mile of gathering line requires an investment of more than $1 million. These investments trigger what we have termed the Marcellus Multiplier. This is the stimulation and engagement of many Pennsylvania businesses that all work in concert to develop natural gas and the resulting circulation of dollars in the state and local economies.

You can see the impact of the Marcellus Multiplier every day in many areas of the Commonwealth. Pennsylvania businesses, both large and small - from restaurants, hotels, trucking companies, car washes, mechanics, construction companies, engineering companies – the development of the Marcellus Shale touches just about every segment of Pennsylvania's economy.

The state and local economic impact of the responsible development of natural gas from the Marcellus is of significant proportion. The Penn State University study previously cited estimates that through 2010, the number of jobs created in relation to the Marcellus amounted to nearly 90,000. By 2020, it is estimated that 212,000 jobs associated with the development of the Marcellus will be added to the Pennsylvania economy. Due to the location of the Marcellus, we are seeing significant business activity and employment opportunities in areas of the Commonwealth that have long lagged behind the state's economy. The industry is committed to hiring and training local talent to fill many of these new jobs as possible. Importing skilled workers is a short term solution to our workforce needs. Many of our companies have partnered with education providers to help train a skilled workforce.

The total economic impact of the Marcellus industry measured by value added is estimated at $8 billion in 2010 and nearly $19 billion by 2020. This economic impact is having an impact on state and local tax revenues. The study by researchers at Penn State estimates that in 2010 alone the impact of Marcellus activity on state and local tax revenues at nearly $800 million; by 2020, this increase in local and state tax revenue is estimated at nearly $1.9 billion dollars. It is important to keep in mind that this revenue impact does not include any windfalls from either the state or local governments leasing any of their land for natural gas production. An example of this can be found in the 2010 Commonwealth leasing of state forest land which resulted in up front bonus payments of approximately $238 million. Future royalties from production on the land could reach several hundred million dollars per year for the Commonwealth.

The impacts of the responsible development of the Marcellus can be further magnified with increased natural gas use in industrial processes, electric generation and transportation. In the transportation sector, increased use of natural gas offers a unique opportunity to provide an effective pathway to achieve a multitude of benefits that include lower-cost fuel, new jobs, enhanced energy security and environmental gains.

Apart from all of these energy and economic impacts, Marcellus companies are working to minimize impacts on the communities in which they are operating. One of the greatest examples is the work that is being done to repair and improve roads in rural Pennsylvania. The industry is working cooperatively with both the state Department of Transportation and municipalities to ensure that any and all damage to posted roads caused by our activities is repaired in a timely manner. In some instances this work is not just limited to repair but improving the roads in rural Pennsylvania. We conservatively estimate that Marcellus operators spent more than $200 million in 2010 to repair and improve roads across the Commonwealth. These are dollars that are not coming out of state or local government coffers. Truck traffic is also being mitigated by the use of temporary pipelines that carry water from centralized impoundments and by the increased use of rail to move products to and from drilling areas.

Some of the transportation impacts of Marcellus activities are traffic related. Constructing a well pad and drilling and completing a well are industrial activities that involve hauling of materials and goods. There is no escaping some of the volume of traffic that comes with Marcellus activities, but many of our members work with local officials to discuss various means to help mitigate the impact of increased traffic on local roads. This past fall, the MSC partnered with the PA State Police, Department of

Transportation, Public Utility Commission, and Department of Environmental Protection on a Marcellus Transportation Safety Day seminar to better educate carriers and truck drivers supporting the industry of the Commonwealth's regulations to improve safe operating practices.

We are also working in a cooperative manner with both state and local officials in the area of public safety. Last May, we launched a partnership with the State Fire Academy to expand training for responders, adding new components targeted specifically at shale gas production. This training covers a host of issues from what to expect upon arriving at a well site to how best to coordinate with on-site industry personnel. This cooperative effort is giving Pennsylvania's first responders the tools needed to respond to the broad range of unlikely scenarios associated with the production of resources from the Marcellus. We understand that more than 2,000 training certificates have been issued to date.

Due to the drilling of multiple wells from one pad and the use of horizontal drilling, our members are lessening surface impacts, and the high percentage of wastewater recycling is making an already low-water use energy source even lower here in Pennsylvania. As previously stated the responsible development of natural gas from the Marcellus is an industrial endeavor. With industrial activities come environmental considerations. Every aspect of our industry is regulated under state and federal environmental rules and regulations. Our activities require various state permits and approvals before any activities take place. Pennsylvania has among the most stringent environmental rules on the books dealing with many aspects of our operations including but not limited to well construction standards, wastewater treatment and disposal requirements, and the regulation of hydraulic fracturing. A national review of Pennsylvania's oversight and regulation of hydraulic fracturing by the State Review of Oil and Natural Gas Environmental Regulations noted the Commonwealth merits special recognition in this area. The members of the MSC are committed to adhering to all applicable environmental laws and regulations in the development of this great resource.

Our hope is that together, we can continue a constructive dialogue on the impacts of Marcellus development, keeping in mind the tremendous benefits that can accrue to the Commonwealth and its citizens and work to fashion a public policy environment that encourages competitive economics while promoting the safe and responsible development of this abundant resource for generations to come.

Thank you.

TESTIMONY SUBMITTED FOR

THE JOINT HEARING OF
THE U.S. SENATE COMMITTEE ON ENVIRONMENT AND PUBLIC WORKS

WITH THE SUBCOMMITTEE ON WATER AND WILDLIFE

ENTITLED

"NATURAL GAS DRILLING: PUBLIC HEALTH AND ENVIRONMENTAL IMPACTS"

BY

MICHEL J. (MIKE) PAQUE

GROUND WATER PROTECTION COUNCIL

APRIL 11, 2011

Madame Chair, thank you for the opportunity to submit this brief written testimony concerning a new, and , we believe significant ,improvement in providing the public a place online where they can go to find useful information on hydraulic fracturing related to natural gas and oil production.

The states have regulated oil and gas production for over eighty years including that part of the drilling process so much in the news today, hydraulic fracturing. While all states agencies have websites dedicated to providing the public information about what they do, how they do it, and how to get more information, what has not existed until two days ago was a single public site for all states that contained useful information about the process of hydraulic fracturing, chemicals used, groundwater, and multi - state related data. I am pleased to tell you that the new Fracfocus website, a joint venture of the Ground Water Protection Council (GWPC) and the Interstate Oil and Gas Compact Commission (IOGCC), will meet these needs. Launched on April 11th, fracfocus.org is a groundbreaking website that will help the public get immediate answers to questions and concerns related to hydraulic fracturing of oil and gas wells in their community, regardless of where they live. Fracfocus, although supported by all states, exists independent of any one state and does not supplant state rules and regulations.

Companies will submit information on the chemicals used in hydraulic fracturing to fracfocus.org. The information will be reported using a template that describes the location of the individual wells, API number, fracture date , operator name, well name and number, latitude and longitude, true vertical depth of the well, and the total volume of water used in the fracture procedure. Also reported will be the hydraulic fracturing fluid composition, including: Chemical trade name, supplier, purpose, chemicals used, Chemical Abstract Service (CAS) number, maximum ingredient concentration (% by mass), and the maximum ingredient concentration in the hydraulic fracture fluid (% by mass). Chemicals that meet the federal legal standard of 29 CFR 1910.1200 (i) and Appendix D for Confidential Business Information (proprietary) will be reported as such. Before using the site, the companies must agree to that standard, and requesting that the suppliers abide by it.

Fracfocus will also offer the user valuable information about ground water hydrology and safety, how to get a private water well checked, and suggestions on what types of chemicals to test for prior to drilling. There is information about those chemicals most commonly used in hydraulic fracturing, the proportions typically used, and some of the federal laws that apply to disclosure. There are also links to USGS ground water information, USDOE, USEPA's National Center for Computational Toxicology, Integrated Risk Information System, and Hydraulic Fracturing websites. It also links to the National Institute of Standards and Technology and the joint OSHA/USEPA Occupational Chemical Data Base.

Although participation is voluntary, within the first 8 hours of "going live" fracfocus.org had 24 oil and gas companies signed on to use it and 9 already uploading fracturing data for 309 wells. Based on level of interest, requests for assistance, and encouragement from the state regulatory agencies, we expect that number to increase significantly. A list of participating companies can be found on the website itself.

The public information portion of the site is dynamic and will be expanded to include more useful information in the weeks and months ahead. We would like to thank the USDOE Office of Fossil Energy for its encouragement and support in building what we hope will become a destination site for citizens interested in, or concerned about, drilling activity in their community. Thank You.

U.S. SENATE COMMITTEE ON ENVIRONMENT AND PUBLIC WORKS AND SUBCOMMITTEE ON WATER AND WILDLIFE
JOINT HEARING
"Natural Gas Drilling: Public Health and Environmental Impacts." Tuesday, April 12, 2011
Written Comments
Oklahoma Independent Petroleum Association

The following information is being submitted to the Committee in response to the April 12, 2011, hearing before the U.S. Senate Environment and Public Works Committee on the public health and environmental impacts of natural gas drilling.

The OIPA represents more than 2,000 small to large independent operators that explore for and produce crude oil and natural gas in the State of Oklahoma. Our association represents a number of oilfield service companies that provide important services that support exploration and production activities. However, our members do not refine oil into gasoline or heating fuels and do not market gasoline.

Independent producers are now, more than ever, aggressively searching for domestic crude oil and natural gas reserves. Operators are using new technology to enhance mature conventional oil fields and focus new attention on unconventional resource plays. Technology is helping independents find and recover more domestic oil and natural gas to make our country more energy secure and less reliant on foreign sources of energy.

Hydraulic fracturing is a proven technology with a long history of environmentally safe use in the completion of crude oil and natural gas wells. Hydraulic fracturing has its roots in Oklahoma, where the practice was pioneered in 1948. Used commercially since 1949, the use of hydraulic fracturing has developed into a routine technology that is frequently used in the completion of natural gas wells, particularly those in "unconventional" resource plays like shale reservoirs. In Oklahoma, hydraulic fracturing has been used for over 60 years with more than 100,000 Oklahoma wells having been hydraulically fractured over that period. During that time, there has not been a single documented instance of contamination to groundwater or drinking water as a result of hydraulic fracturing.

The lack of incidents can be attributed to the comprehensive laws and regulations Oklahoma has in place to provide for safe operations and the protection of drinking water sources and trained personnel to effectively regulate all aspect of the crude oil and natural gas drilling, completion, production and plugging operations, which includes hydraulic fracturing.

In 2010, Oklahoma volunteered to have its hydraulic fracturing regulations reviewed by the State Review of Oil and Natural Gas Environmental Regulations, known as STRONGER. STRONGER was formed in 1999 to reinvigorate and carry forward the state review process begun cooperatively in 1988 by the U.S. Environmental Protection Agency and the Interstate Oil and Gas Compact Commission. The state review process is a collaborative process by which review teams composed of stakeholders from the oil and gas industry, state environmental regulatory programs, and members of the environmental/public interest communities review state oil and gas waste management programs against a set of guidelines developed and agreed to by all the participating parties. The review team concluded that the Oklahoma program is, overall, well managed, professional and meets STRONGER's program objectives.

OIPA believes the State is the most appropriate regulatory body to provide oversight and protection of hydrologically and environmentally sensitive localities as they relate to hydraulic fracturing. The geology differs among and within states. Water use is a local issue and is best allocated by state/local authorities. The State has better knowledge of specific aquifers and producing oil and gas formations. States are more flexible in it regulatory oversight and can adopt rules for specific geographic areas, i.e. field rules. States can adopt and amend rules quickly to respond to changing circumstances and technology, and State inspectors live in the area and can react more quickly to issues that arise. Because of these variables, a one-size-fits-all federal approach is not appropriate.

In Oklahoma and other energy-producing states, citizens understand the importance of the oil and natural gas industry. Those of us who live close to the wellhead understand the impact this industry has on jobs and the overall economy, both locally and nationally. As oil and natural gas production moves into states that have traditionally seen little to no energy exploration, a lack of understanding about the drilling process and the industry as a whole leads to confusion and, in some cases, fear.

Our member companies take their environmental responsibilities very seriously. We live, work and play in the areas where we produce crude oil and natural gas. The oil and natural gas industry has voluntarily offered information on the hydraulic fracturing process and the chemicals used in it. A joint project of the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission, the "FracFocus" website offers an online registry that allows participating oil and natural gas companies to provide information about the chemicals used in the hydraulic fracturing of oil and natural gas wells. This project became fully operational this month and already 34 companies have provided information for the site. The primary purpose of the site is to provide the public factual information concerning hydraulic fracturing and groundwater protection.

We cannot emphasize enough how important our industry is to Oklahoma and the nation. Oklahoma is the nation's third-largest producer of natural gas, sixth-largest producer of crude oil, has the third greatest number of active drilling rigs and ranks fifth in crude oil reserves. As a whole, the oil energy industry contributes $23 billion to Oklahoma's gross domestic product. Oklahoma has one of the fastest growing economies in the nation, ranking among the top states in per capita income growth and gross domestic product growth. Without hydraulic fracturing, Oklahoma would not be able to produce the domestic energy our nation needs and keep Oklahoma strong in these times of national economic uncertainty.

In conclusion, Oklahoma is effectively regulating and managing hydraulic fracturing operations and as such, federal regulations are not warranted nor are they appropriate. Thank you for your time and consideration of these comments.

TESTIMONY SUBMITTED TO Members of the Senate Environment and Public Works Committee

BY LYNN D. HELMS, DIRECTOR OF THE DEPARTMENT OF MINERAL RESOURCES INDUSTRIAL COMMISSION OF THE STATE OF NORTH DAKOTA

APRIL 7, 2011

Dear Senators:

Thank you for this opportunity to provide information on the comprehensive life cycle regulation of hydraulic fracturing by the state of North Dakota.

I will begin with some information on the Bakken shale formation in North Dakota and, how, thanks to recent technological advances, it is providing this country with an abundant and critical domestic energy resource. I will also provide testimony as to the competency and commitment of our state regulators to protect the drinking water resources of North Dakota's citizens while developing this abundant shale energy resource.

North Dakota's Bakken Resource

Let me begin by talking about the Bakken formation. The Bakken is a large unconventional oil and gas resource that underlies most of western North Dakota, eastern Montana, southeast Saskatchewan, and southwest Manitoba. The U.S. Geological Survey (USGS) stated in April 2008 that it is the largest continuous resource they have ever assessed in the lower 48 states.

The upper and lower members of the Bakken formation are world class petroleum source rocks. The geological models based on input from North Dakota Geological Survey geologists, samples from the North Dakota Core and Sample Library, and the well files from the North Dakota Oil and Gas Division establish the most likely range of oil and gas in-place at 300-500 billion barrels of oil and 300-500 trillion cubic feet of associated natural gas.

This incredible resource was identified by geologists within months of the first commercial oil production in North Dakota in a well drilled on a farm north of Tioga, ND in 1951. Yet, economic production was rare until the remarkable technologies of deep, long horizontal wells with multiple hydraulic fracture treatments. Because of these new technologies that now make it possible to economically produce the Bakken formation the state of North Dakota has recently moved from number 9 in daily oil production to 4th.

The Bakken play in North Dakota is still in the learning curve and operators are still modifying the drilling and completion practices. While it is apparent that technology and the price of oil will dictate what is recoverable from this formation, the current recoverable reserves estimate equals all U.S. crude oil imports from the Persian Gulf since 2000 and a full year of residential natural gas consumption for our nation. The productive portion of the Bakken occupies over 8.4 million acres in western North Dakota and full development is expected to require 15 to 20 years and over 26,000 new wells each hydraulically fractured. This is lot of energy for our country and jobs for the American economy.

State Regulation of Oil and Natural Gas

I'd like to now address the issue of how development of this shale resource in North Dakota, and throughout the country, is regulated so as to also protect and preserve our country's precious water resources. It is useful to understand the critical role that states play in the regulation of oil and natural gas resources in the United States. A brief history of oil and natural gas in North Dakota can serve as an illustrative example.

North Dakota Oil and Gas Regulatory History

In response to shallow natural gas discoveries used for domestic lighting and heating the North Dakota Legislature passed an oil and gas conservation law that prohibited production of gas unless it was tied to a distribution system in 1911. The 1941 Legislature later passed the first meaningful regulatory bill under the urging of then State Geologist Wilson M. Laird. As a result, North Dakota had an oil-conservation law in place when oil was discovered in the State ten years later, but following that first commercial oil production in April 1951 North Dakota saw the need to be part of the organization chartered by congress to assist states with oil and gas regulation. North Dakota joined the Interstate Oil Compact Commission in 1953 and the North Dakota Legislature revised the Oil and Gas Conservation Law to conform to the IOCC Model Act that same year.

As the head regulator of oil and natural gas development in the State of North Dakota I can assure you that we have no higher priority than the protection of our states' water resources – let me repeat no higher priority. Much of our entire regulatory framework, from drilling to completion, production, and finally plugging and abandonment, is centered around measures to prevent any contamination of the water resource. As a component of the completion of a well, hydraulic fracturing operations are thus thoroughly regulated and supervised by the states.

A major component of production operations is the proper storage and disposal of all production wastes, including hydraulic fracturing flow back water. These operations are carefully monitored, audited, and regulated in our state programs.

Hydraulic Fracturing Is Environmentally Safe

In a 1998 survey of state oil and gas regulatory agencies conducted by the Ground Water Protection Council twenty four state programs said they had not recorded any complaints of contamination to a USDW that the agency could attribute to hydraulic fracturing of coalbed methane zones.

In 2004 the Environmental Protection Agency published a final report summarizing a study to evaluate the potential threat to underground sources of drinking water from hydraulic fracturing of coal bed methane production wells concluding that "additional or further study is not warranted at this time..." and that "the injection of hydraulic fracturing fluids into coal bed methane wells poses minimal threat to the underground sources of drinking water".

Subsequently, the IOGCC conducted a survey of North Dakota and other oil and gas-producing states that found that there were no known cases of ground water contamination associated with hydraulic fracturing. Hydraulic fracturing is a common operation used in exploration and production by the oil and gas industry in North Dakota and all the member states of the IOGCC. Over 35,000 wells are hydraulically fractured annually in the United States, and over one million wells have been hydraulically fractured in the United States since the technique's inception, with no known harm to ground water.

Complaints of ground water contamination attributed to hydraulic fracturing or any other oil and gas operation should continue to be investigated by the appropriate state agency or agencies to determine whether or not ground water has been affected and whether a cause and effect relationship can be established between any impacts to ground water and petroleum exploration and production activities.

Pages 4 through 25 of my testimony illustrate how for decades the state of North Dakota through its various regulatory agencies has protected the health and welfare of our citizens throughout the complete life cycle of the hydraulic fracturing process and in fact throughout the total life cycle of the oil and gas extraction process.

Summary

The state of North Dakota and the IOGCC are firmly committed to the premise that regulation of oil and gas field activities is managed best at the state level where regional and local conditions are understood and where regulations can be tailored to fit the needs of the local environment. Federal regulatory programs have been most effective when they have been delegated to state regulatory agencies and funded through primacy programs. The primary example of this success has been the 1974 Safe Drinking Water Act (SDWA) section called the Underground Injection Control (UIC) Program. Between 1982 and 1990, twenty oil producing states applied for and received primary enforcement authority (primacy) from EPA to administer the program under Section 1425 of SDWA. Delegation of authority for this program to the states has required those with oil and gas regulatory programs to demonstrate that their programs were equally effective in protecting ground water as those promulgated and administered by EPA under Section 1422 of SDWA. Federal regulatory programs that can not be delegated to state regulatory agencies and funded through primacy programs have been a constant source of friction between regulators and it has been much more difficult to achieve compliance. The primary example of this success has been the 1990 Oil Pollution Act (OPA) and Spill Prevention Control and Countermeasure (SPCC) regulations.

However, regulations alone don't begin to provide the full measure of a regulatory program. The North Dakota Oil and Gas Division of the Department of Mineral Resources utilizes performance measures to monitor our activity in the areas of permitting, wellbore construction, well bore mechanical integrity testing, spill containment and clean up, fluid measurement, oil and gas conservation, and customer satisfaction. At least five of these measures are directly related to protection of water resources. These performance measures are backed up by a staff of field inspectors who visit the wells every day from when the drilling rig moves in until the permanent wellhead is installed and at least quarterly after that.

TESTIMONY ON HYDRAULIC FRACTURING OF OIL AND GAS WELLS IN MICHIGAN

Harold R. Fitch
Chief, Office of Geological Survey
Michigan Department of Environmental Quality
April 11, 2011

Michigan is characteristic of other oil and gas producing states in having comprehensive laws and regulations that effectively regulate hydraulic fracturing as well as every other aspect of oil and gas drilling and production. In Michigan those laws and regulations are enforced by the Department of Environmental Quality (DEQ). Hydraulic fracturing has been used for decades in Michigan, and more than 12,000 oil and gas wells have been hydraulically fractured in the state. There is no indication that hydraulic fracturing has ever caused any adverse impacts to the environment or public health in Michigan.

That is not to discount concerns over potential impacts of oil and gas development. No industrial operation is fail-safe, and occasional accidents may happen. As a state agency, we stress the importance of staying vigilant and adaptable in order to minimize the risk of accidents.

A major concern in oil and gas development is the prevention of migration of gas or other fluids out of the wellbore and into fresh water aquifers or surface water. In cases where this has occurred, it has been the result of well construction problems and not of hydraulic fracturing itself. The key to preventing migration of gas or fluids is the installation of steel pipe ("casing"), sealed in place with cement. Michigan regulations require a specific casing and cementing plan for each oil and gas well that will effectively contain gas and other fluids within the wellbore. Other oil and gas producing states have similar requirements.

Proper management of flowback water (water injected for hydraulic fracturing that is subsequently recovered from the well) is another important element in protecting public health and the environment. In Michigan, all flowback water must be contained and transported to disposal wells where it is injected into deep rock layers that are isolated from fresh water supplies. In other regions recycling of flowback water may be a viable option, and other means of disposal may be effective if the flowback fluids are monitored and processed properly.

Another concern has been the disclosure of chemical additives used in hydraulic fracturing. While the details on some chemical compounds are protected as trade secrets under federal law, information on the chemical class and characteristics of additives is available in Material Safety Data Sheets (MSDS). The MSDSs must be posted wherever the additives are stored, transported, or used. They show the potential health and environmental effects of each chemical—whether the chemical formula is proprietary or not—and provide guidance to emergency responders and medical personnel. The DEQ reviews MSDSs and is currently working on avenues to make them more accessible to others. We support the current program by the Groundwater Protection Council and Interstate Oil and Gas Compact Commission to publish a nationwide registry of chemical additives.

If the United States is to be more self-sufficient and maintain a reasonable cost for its energy supply, hydraulic fracturing will have a vital role to play. We believe state regulators have the necessary technical expertise and legal structures to assure that hydraulic fracturing is done is a safe manner. A key element is the ability of each state to adapt its laws and regulations to its own unique circumstances.

REGULATORY STATEMENTS ON HYDRAULIC FRACTURING
SUBMITTED BY THE STATES
JUNE 2009

The following statements were issued by state regulators for the record related to hydraulic fracturing in their states. Statements have been compiled for this document.

ALABAMA:

Nick Tew, Ph.D., P.G.
Alabama State Geologist & Oil and Gas Supervisor
President, Association of American State Geologists

There have been no documented cases of drinking water contamination that have resulted from hydraulic fracturing operations to stimulate oil and gas wells in the State of Alabama.

The U.S. Environmental Protection Agency (EPA) approved the State Oil and Gas Board of Alabama's (Board) Class II Underground Injection Control (UIC) Program in August 1982, pursuant to Section 1425 of the Safe Drinking Water Act (SDWA). This approval was made after EPA determined that the Board's program accomplished the objectives of the SDWA, that is, the protection of underground sources of drinking water. Obtaining primacy for the Class II UIC Program, however, was not the beginning of the Board's ground-water protection programs. These programs, which include the regulation and approval of hydraulic fracturing operations, have been continuously and actively implemented since the Board was established in 1945, pursuant to its mission and legislative mandates.

The State of Alabama, acting through the Board, has a vested interest in protecting its drinking water sources and has adequate rules and regulations, as well as statutory mandates, to protect these sources from all oil and gas operations, including hydraulic fracturing. The fact that there has been no documented case of contamination from these operations, including hydraulic fracturing, is strong evidence of effective regulation of the industry by the Board. In our view, additional federal regulations will not provide any greater level of protection for our drinking water sources than is currently being provided.

ALASKA:

Cathy Foerster
Commissioner
Alaska Oil and Gas Conservation Commission

There have been no verified cases of harm to ground water in the State of Alaska as a result of hydraulic fracturing.

State regulations already exist in Alaska to protect fresh water sources. Current well construction standards used in Alaska (as required by Alaska Oil and Gas Conservation Commission statutes and regulations) properly protect fresh drinking waters. Surface casing is always set well below fresh waters and cemented to surface. This includes both injectors and producers as the casing/cementing programs are essentially the same in both types of wells. There are additional casings installed in wells as well as tubing which ultimately connects the reservoir to the surface. The AOGCC requires rigorous testing to demonstrate the effectiveness of these barriers protecting fresh water sources.

By passing this legislation [FRAC Act] it is probable that every oil and gas well within the State of Alaska will come under EPA jurisdiction. EPA will then likely set redundant construction guidelines and testing standards that will merely create duplicate reporting and testing requirements with no benefit to the environment. Additional government employees will be required to monitor the programs, causing further waste of taxpayer dollars.

Material safety data sheets for all materials used in oil and gas operations are required to be maintained on location by Hazard Communication Standards of OSHA. Therefore, requiring such data in the FRAC bill is, again, merely duplicate effort with and accomplishes nothing new.

COLORADO:

David Neslin
Director
Colorado Oil and Gas Conservation Commission

To the knowledge of the Colorado Oil and Gas Conservation Commission staff, there has been no verified instance of harm to groundwater caused by hydraulic fracturing in Colorado.

INDIANA:

Herschel McDivitt
Director
Indiana Department of Natural Resources

There have been no instances where the Division of Oil and Gas has verified that harm to groundwater has ever been found to be the result of hydraulic fracturing in Indiana. In fact, we are unaware of any allegations that hydraulic fracturing may be the cause of or may have been a contributing factor to an adverse impact to groundwater in Indiana.

The Division of Oil and Gas is the sole agency responsible for overseeing all aspects of oil and gas production operations as directed under Indiana's Oil and Gas Act. Additionally, the Division of Oil and Gas has been granted primacy by the U.S. Environmental Protection Agency, to implement the Underground Injection Control (UIC) Program for Class II wells in Indiana under the Safe Drinking Water Act.

KENTUCKY:

Kim Collings, EEC
Director
Kentucky Division of Oil and Gas

In Kentucky, there have been alleged contaminations from citizen complaints but nothing that can be substantiated, in every case the well had surface casing cemented to surface and production casing cemented.

LOUISIANA:

James Welsh
Commissioner of Conservation
Louisiana Department of Natural Resources

The Louisiana Office of Conservation is unaware of any instance of harm to groundwater in the State of Louisiana caused by the practice of hydraulic fracturing. My office is statutorily responsible for regulation of the oil and gas industry in Louisiana, including completion technology such as hydraulic fracturing, underground injection and disposal of oilfield waste operations, and management of the major aquifers in the State of Louisiana.

MICHIGAN:

Harold Fitch
Director, Office of Geological Survey
Department of Environmental Quality

My agency, the Office of Geological Survey (OGS) of the Department of Environmental Quality, regulates oil and gas exploration and production in Michigan. The OGS issues permits for oil and gas wells and monitors all aspects of well drilling, completion, production, and plugging operations, including hydraulic fracturing.

Hydraulic fracturing has been utilized extensively for many years in Michigan, in both deep formations and in the relatively shallow Antrim Shale formation. There are about 9,900 Antrim wells in Michigan producing natural gas at depths of 500 to 2000 feet. Hydraulic fracturing has been used in virtually every Antrim well.

There is no indication that hydraulic fracturing has ever caused damage to ground water or other resources in Michigan. In fact, the OGS has never received a complaint or allegation that hydraulic fracturing has impacted groundwater in any way.

OKLAHOMA:

Lori Wrotenbery
Director, Oil and Gas Conservation Division
Oklahoma Corporation Commission

You asked whether there has been a verified instance of harm to groundwater in our state from the practice of hydraulic fracturing. The answer in no. We have no documentation of such an instance. Furthermore, I have consulted the senior staffs of our Pollution Abatement Department, Field Operations Department, and Technical Services Department, and they have no recollection of having ever received a report, complaint, or allegation of such an instance. We also contacted the senior staffs of the Oklahoma Department of Environmental Quality, who likewise, have no such knowledge or information.

While there have been incidents of groundwater contamination associated with oil and gas drilling and production operations in the State of Oklahoma, none of the documented incidents have been associated with hydraulic fracturing. Our agency has been regulating oil and gas drilling and production operations in the state for over 90 years. Tens of thousands of hydraulic fracturing operations have been conducted in the state in the last 60 years. Had hydraulic fracturing caused harm to groundwater in our state in anything other than a rare and isolated instance, we are confident that we would have identified that harm in the course of our surveillance of drilling and production practices and our investigation of groundwater contamination incidents.

TENNESSEE:

Paul Schmierbach
Manager
Tennessee Department of Environmental Conservation

We have had no reports of well damage due to fracking.

TEXAS:

Victor G. Carrillo
Chairman
Railroad Commission of Texas

The practice of reservoir stimulation by hydraulic fracturing has been used safely in Texas for over six decades in tens of thousands of wells across the state.

Recently in his introductory Statement for the Record (June 9, 2009) of the Fracturing Responsibility and Awareness of Chemicals (FRAC) Act, Senator Robert Casey stated:

> "Now, the oil and gas industry would have you believe that there is no threat to drinking water from hydraulic fracturing. But the fact is we are already seeing cases in Pennsylvania, Colorado, Virginia, West Virginia, Alabama, Wyoming, Ohio, Arkansas, Utah, Texas, and New Mexico where residents have become ill or groundwater has become contaminated after hydraulic fracturing operations began in the area."

This statement perpetuates the misconception that there are many surface or groundwater contamination cases in Texas and other states due to hydraulic fracturing. This is not true and here are the facts: Though hydraulic fracturing has been used for over 60 years in Texas, our Railroad Commission records ***do not reflect a single documented surface or groundwater contamination case associated with hydraulic fracturing***.

Hydraulic fracturing plays a key role in the development of unconventional gas resources in Texas. As of this year, over 11,000 gas wells have been completed - and hydraulically fractured - in the Newark East (Barnett Shale) Field, one of the nation's largest and most active natural gas fields. Since 2000, over 5 Tcf (trillion cubic feet) of gas has been produced from this one reservoir and Barnett Shale production currently contributes over 20% of total Texas natural gas production (over 7 Tcf in 2008 – more than a third of total U.S. marketed production). While the volume of gas-in-place in the Barnett Shale is estimated to be over 27 Tcf, conventional recovery of the gas is difficult because of the shale's low permeability. The remarkable success of the Barnett Shale results in large part from the use of horizontal drilling coupled with hydraulic fracturing. Even with this intense activity, there are no known instances of ongoing surface or groundwater contamination in the Barnett Shale play.

Regulating oil and gas exploration and production activities, including hydraulic fracturing, has traditionally been the province of the states, which have had effective programs in place for decades. Regulating hydraulic fracturing as underground injection under the federal Safe Drinking Water Act would impose significant additional costs and regulatory burdens and could ultimately reverse the significant U.S. domestic unconventional gas reserve additions of recent years – substantially harming domestic energy security. Congress should maintain the status quo and let the states continue to responsibly regulate oil and gas activities, including hydraulic fracturing.

In summary, I am aware of no verified instance of harm to groundwater in Texas from the decades long practice of hydraulic fracturing.

SOUTH DAKOTA:

Fred Steece
Oil and Gas Supervisor
Department of Environment and Natural Resource

Oil and gas wells have been hydraulically fractured, "fracked," in South Dakota since oil was discovered in 1954 and since gas was discovered in 1970. South Dakota has had rules in place, dating back to the 1940's, that require sufficient surface casing and cement to be installed in wells to protect ground water supplies in the state's oil fields. Producing wells are required to have production casing and cement, and tubing with packers installed. The casing, tubing, and cement are all designed to protect drinking waters of the state as well as to prevent commingling of water and oil and gas in the subsurface. In the 41 years that I have supervised oil and gas exploration, production and development in South Dakota, no documented case of water well or aquifer damage by the fracking of oil or gas wells, has been brought to my attention. Nor am I aware of any such cases before my time.

WYOMING:

Rick Marvel
Engineering Manager
Wyoming Oil and Gas Conservation Commission

Tom Doll
Oil and Gas Commission Supervisor
Wyoming Oil and Gas Conservation Commission

- No documented cases of groundwater contamination from fracture stimulations in Wyoming.

- No documented cases of groundwater contamination from UIC regulated wells in Wyoming.

- Wyoming took primacy over UIC Class II wells in 1982, currently 4,920 Class II wells permitted.

Wyoming's 2008 activity:

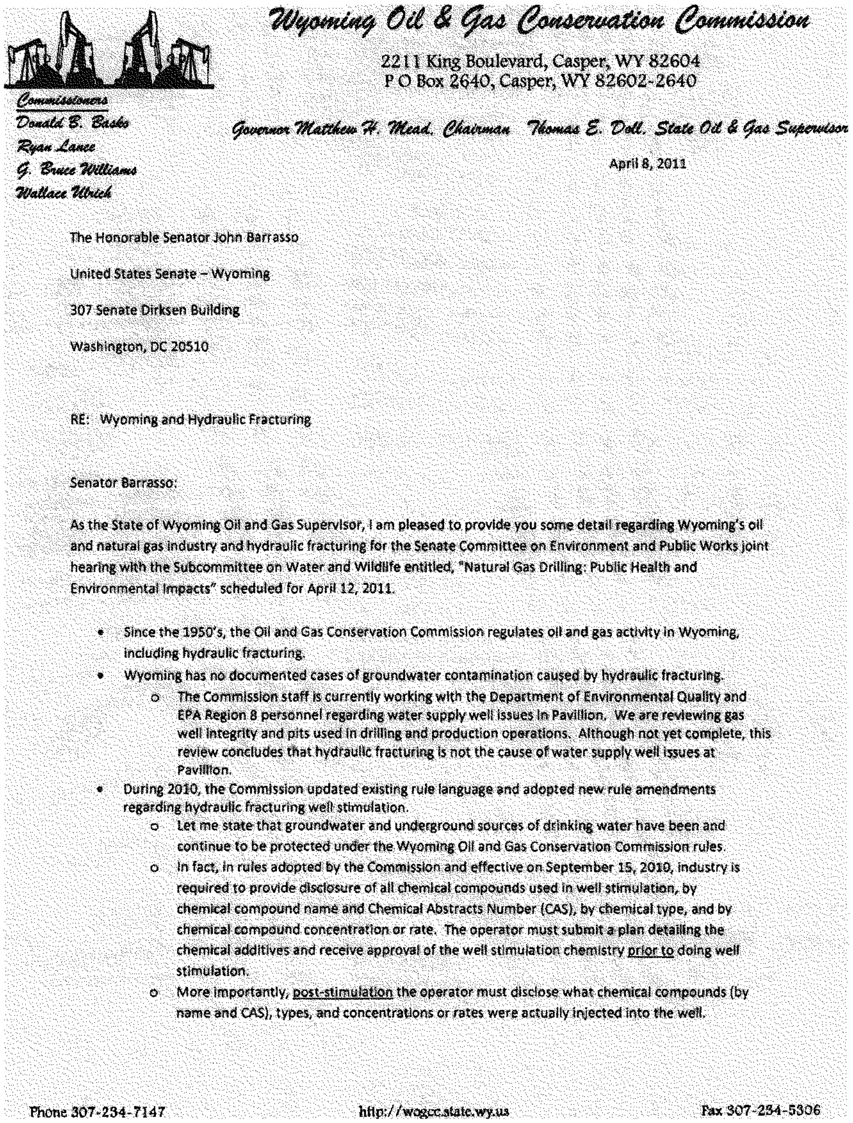
- Powder River Basin Coalbed Wells – 1,699 new wells, no fracture stimulation.
- Rawlins Area (deeper) Coalbed Wells – 109 new wells, 100% fracture stimulated.
- Statewide Conventional Gas Wells – 1,316 new wells, 100% fracture stimulated – many wells with multi-zone fracture stimulations in each well bore, some staged and some individual fracture stimulations.
- Statewide Oil Wells – 237 new wells, 75% fracture stimulated.

The Wyoming Oil and Gas Commission Rules and Regulations are specific in requiring the operator receive approval prior to performing hydraulic fracturing treatments. The Rules require the operator to provide detailed information regarding the hydraulic fracturing process, to include the source of water and/or trade name fluids, type of proponents, as well as estimated pump pressures. After the treatment is complete the operator is required to provide actual fracturing data in detail and resulting production results.

Under Chapter 3, Section 8 (c) The Application for Permit to Drill or Deepen (Form 1) states..."information shall also be given relative to the drilling plan, together with any other information which may be required by the Supervisor. Where multiple Applications for Permit to Drill will be sought for several wells proposed to be drilled to the same zone within an area of geologic similarity, approval may be sought from the Supervisor to file a comprehensive drilling plan containing the information required above which will then be referenced on each Application for Permit to Drill." Operators have been informed by Commission staff to include detailed information regarding the hydraulic fraction stimulation process on the Form 1 Application for Permit to Drill.

The Rules also state, in Chapter 3, Section 1 (a) "A written notice of intention to do work or to change plans previously approved on the original APD and/or drilling and completion plan (Chapter 3, Section 8 (c)) must be filed with the Supervisor on the Sundry Notice (Form 4), unless otherwise directed, and must reach the Supervisor and receive his approval before the work is begun. Approval must be sought to acidize, cleanout, flush, fracture, or stimulate a well. The Sundry Notice must include depth to perforations or the openhole interval, the source of water and/or trade name fluids, type proponents, as well as estimated pump pressures. Routine activities that do not affect the integrity of the wellbore or the reservoir, such as pump replacements, do not require a Sundry Notice. The Supervisor may require additional information." Most operators will submit the Sundry Notice Form 4 to provide the specific detail for the hydraulic fracturing treatment even though the general information might have been provided under the Form 1 Application for Permit to Drill.

After the hydraulic fracture treatment is complete, results must be reported to the Supervisor. Chapter 3, Section 12 Well Completion or Recompletion Report and Log (Form 3) state "upon completion or recompletion of a well, stratigraphic test or core hole, or the completion of any remedial work such as plugging back or drilling deeper, acidizing, shooting, formation fracturing, squeezing operations, setting a liner, gun perforating, or other similar operations not specifically covered herein, a report on the operation shall be filed with the Supervisor. Such report shall present a detailed account of the work done and the manner in which such work was performed; the daily production of the oil, gas, and water both prior to and after the operation; the size and depth of perforations; the quantity of sand, crude, chemical, or other materials employed in the operation and any other pertinent information of operations which affect the original status of the well and are not specifically covered herein."



Wyoming Oil & Gas Conservation Commission

2211 King Boulevard, Casper, WY 82604
P O Box 2640, Casper, WY 82602-2640

Commissioners
Donald B. Basko
Ryan Lance
G. Bruce Williams
Wallace Ulrich

Governor Matthew H. Mead, Chairman *Thomas E. Doll, State Oil & Gas Supervisor*

April 8, 2011

The Honorable Senator John Barrasso

United States Senate – Wyoming

307 Senate Dirksen Building

Washington, DC 20510

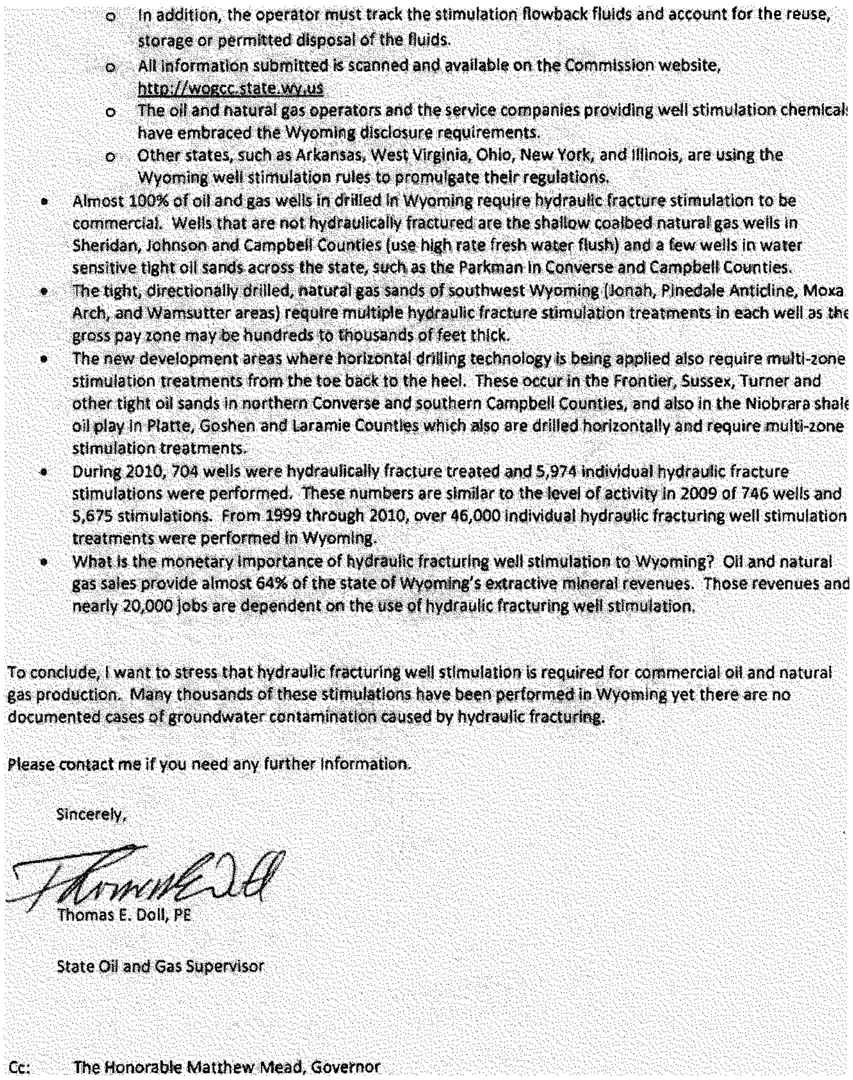
RE: Wyoming and Hydraulic Fracturing

Senator Barrasso:

As the State of Wyoming Oil and Gas Supervisor, I am pleased to provide you some detail regarding Wyoming's oil and natural gas industry and hydraulic fracturing for the Senate Committee on Environment and Public Works joint hearing with the Subcommittee on Water and Wildlife entitled, "Natural Gas Drilling: Public Health and Environmental Impacts" scheduled for April 12, 2011.

- Since the 1950's, the Oil and Gas Conservation Commission regulates oil and gas activity in Wyoming, including hydraulic fracturing.
- Wyoming has no documented cases of groundwater contamination caused by hydraulic fracturing.
  - The Commission staff is currently working with the Department of Environmental Quality and EPA Region 8 personnel regarding water supply well issues in Pavillion. We are reviewing gas well integrity and pits used in drilling and production operations. Although not yet complete, this review concludes that hydraulic fracturing is not the cause of water supply well issues at Pavillion.
- During 2010, the Commission updated existing rule language and adopted new rule amendments regarding hydraulic fracturing well stimulation.
  - Let me state that groundwater and underground sources of drinking water have been and continue to be protected under the Wyoming Oil and Gas Conservation Commission rules.
  - In fact, in rules adopted by the Commission and effective on September 15, 2010, industry is required to provide disclosure of all chemical compounds used in well stimulation, by chemical compound name and Chemical Abstracts Number (CAS), by chemical type, and by chemical compound concentration or rate. The operator must submit a plan detailing the chemical additives and receive approval of the well stimulation chemistry prior to doing well stimulation.
  - More importantly, post-stimulation the operator must disclose what chemical compounds (by name and CAS), types, and concentrations or rates were actually injected into the well.

Phone 307-234-7147 http://wogcc.state.wy.us Fax 307-234-5306



  - In addition, the operator must track the stimulation flowback fluids and account for the reuse, storage or permitted disposal of the fluids.
  - All information submitted is scanned and available on the Commission website, http://wogcc.state.wy.us
  - The oil and natural gas operators and the service companies providing well stimulation chemicals have embraced the Wyoming disclosure requirements.
  - Other states, such as Arkansas, West Virginia, Ohio, New York, and Illinois, are using the Wyoming well stimulation rules to promulgate their regulations.
- Almost 100% of oil and gas wells in drilled in Wyoming require hydraulic fracture stimulation to be commercial. Wells that are not hydraulically fractured are the shallow coalbed natural gas wells in Sheridan, Johnson and Campbell Counties (use high rate fresh water flush) and a few wells in water sensitive tight oil sands across the state, such as the Parkman in Converse and Campbell Counties.
- The tight, directionally drilled, natural gas sands of southwest Wyoming (Jonah, Pinedale Anticline, Moxa Arch, and Wamsutter areas) require multiple hydraulic fracture stimulation treatments in each well as the gross pay zone may be hundreds to thousands of feet thick.
- The new development areas where horizontal drilling technology is being applied also require multi-zone stimulation treatments from the toe back to the heel. These occur in the Frontier, Sussex, Turner and other tight oil sands in northern Converse and southern Campbell Counties, and also in the Niobrara shale oil play in Platte, Goshen and Laramie Counties which also are drilled horizontally and require multi-zone stimulation treatments.
- During 2010, 704 wells were hydraulically fracture treated and 5,974 individual hydraulic fracture stimulations were performed. These numbers are similar to the level of activity in 2009 of 746 wells and 5,675 stimulations. From 1999 through 2010, over 46,000 individual hydraulic fracturing well stimulation treatments were performed in Wyoming.
- What is the monetary importance of hydraulic fracturing well stimulation to Wyoming? Oil and natural gas sales provide almost 64% of the state of Wyoming's extractive mineral revenues. Those revenues and nearly 20,000 jobs are dependent on the use of hydraulic fracturing well stimulation.

To conclude, I want to stress that hydraulic fracturing well stimulation is required for commercial oil and natural gas production. Many thousands of these stimulations have been performed in Wyoming yet there are no documented cases of groundwater contamination caused by hydraulic fracturing.

Please contact me if you need any further information.

Sincerely,

Thomas E. Doll, PE

State Oil and Gas Supervisor

Cc: The Honorable Matthew Mead, Governor

Ohio | **Environmental Protection Agency**
John R. Kasich, Governor
Mary Taylor, Lt. Governor
Scott J. Nally, Director

April 21, 2011

The Honorable Benjamin L. Cardin
509 Hart Senate Office Building
Washington, D.C. 20510-2004

Dear Senator Cardin:

Thank you for your recent letter asking several questions relating to the hydraulic fracturing of marcellus and utica shale deposits in Ohio. Ohio DNR is the lead agency on permitting for oil and gas mining within our state; however Ohio EPA does have a small role in certain areas. Below are responses for specific questions that pertain to our authority.

1) Ohio EPA permits activities related to oil and gas mining in our state. Activities under our authority are waste water discharges into surface waters (answered in item 2) and any impacts to wetlands in the mining area which may need a US Army Corps of Engineers 404 permit and additionally, certification under Ohio EPA's 401 program. Types of activities that would require Section 401 water quality certification typically include construction of the drill pad site, flowback and fresh water ponds, berms, dikes, access roads and utility lines. Ohio EPA's Division of Surface has not received any applications seeking Section 401 water quality certification for proposed impacts to streams and wetlands at these sites.

2) Currently Ohio has only one permitted discharge of "fracing" water to surface water. The City of Warren (Trumbull County) wastewater treatment plant is authorized to take up to 100,000 gallons per day of wastewater at a concentration of 50,000 mg/L Total Dissolved Solids (TDS), based on the assumptive total maximum daily load (TMDL) of the receiving waters. The waste water must also be pretreated prior to discharge to Warren. I understand Ohio DNR provided information on the volume and types of underground injection in their response.

3) Ohio EPA is currently involved in three separate enforcement actions resulting from the unauthorized placement of fill in either streams or wetlands associated with horizontal drilling sites. Two actions are the result of the direct placement of fill into streams and/or wetlands without proper 404 or 401 permit authorizations. The third action is a result of an unintentional fill as overburden removed from a steep hillside to construct a drilling pad was improperly stabilized and slumped into an adjacent stream. These actions are not specifically related to the hydraulic fracturing, however as previously stated, they have occurred at sites that are using horizontal drilling techniques.

4) There have not been any reported cases of impacts to groundwater caused specifically by hydraulic fracturing in Ohio.

I hope this information is helpful in the Subcommittee's review of this practice. We appreciate the opportunity to answer these questions. Please feel free to contact me or my legislative staff at 614-644-2782 if you have additional questions.

Sincerely,

Scott J. Nally
Director

cc: Director David Mustine, ODNR

dep

west virginia department of environmental protection

Executive Office
601 57th Street SE
Charleston, WV 25304
Phone: (304) 926-0440
Fax: (304) 926-0446

Earl Ray Tomblin, Governor
Randy C. Huffman, Cabinet Secretary
www.dep.wv.gov

April 20, 2011

The Honorable Benjamin L. Cardin
United States Senate
509 Hart Senate Office Building
Washington, DC 20510-2004

Dear Senator Cardin:

I have been assisting with compiling the information you requested in your March 18, 2011 letter to Randy Huffman, Cabinet Secretary for the WV DEP. The last piece of information submitted to you was this past Friday, April 15th, and contained enforcement-related data in response to item number three (3) of your letter.

We just recently discovered that three (3) notices of violation for potential/actual water contamination were omitted from that information. I am enclosing that information and apologize for this oversight.

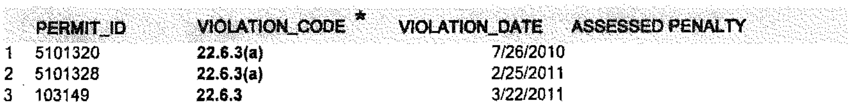
Should you have questions or require additional information, please do not hesitate to contact me.

Sincerely,

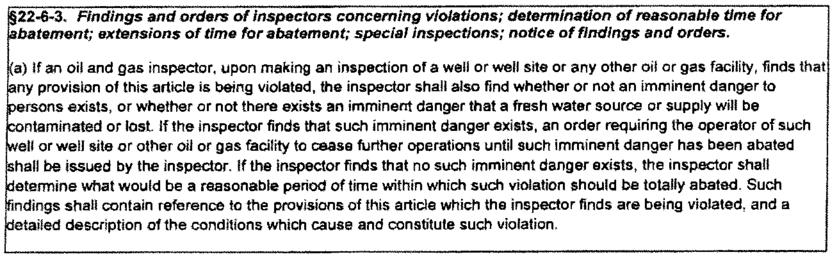
Lisa McClung
Deputy Cabinet Secretary

LM/jmc

Enclosures



	PERMIT_ID	VIOLATION_CODE *	VIOLATION_DATE	ASSESSED PENALTY
1	5101320	**22.6.3(a)**	7/26/2010	
2	5101328	**22.6.3(a)**	2/25/2011	
3	103149	**22.6.3**	3/22/2011	



* **§22-6-3. *Findings and orders of inspectors concerning violations; determination of reasonable time for abatement; extensions of time for abatement; special inspections; notice of findings and orders.***

(a) If an oil and gas inspector, upon making an inspection of a well or well site or any other oil or gas facility, finds that any provision of this article is being violated, the inspector shall also find whether or not an imminent danger to persons exists, or whether or not there exists an imminent danger that a fresh water source or supply will be contaminated or lost. If the inspector finds that such imminent danger exists, an order requiring the operator of such well or well site or other oil or gas facility to cease further operations until such imminent danger has been abated shall be issued by the inspector. If the inspector finds that no such imminent danger exists, the inspector shall determine what would be a reasonable period of time within which such violation should be totally abated. Such findings shall contain reference to the provisions of this article which the inspector finds are being violated, and a detailed description of the conditions which cause and constitute such violation.

dep

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Earl Ray Tomblin, Governor
Randy C. Huffman, Cabinet Secretary
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April 15, 2011

The Honorable Benjamin L. Cardin
United States Senate
509 Hart Senate Office Building
Washington, DC 20510-2004

Dear Senator Cardin:

The purpose of this letter is to follow up with you on my April 7, 2011 response letter and to provide the information you requested on March 18, 2011. Specifically, I will be addressing the information you requested in item number three of that correspondence and for which we had received some additional time to submit through a discussion with Mr. Mike Burke of your staff.

3) Records of any enforcement actions taken relating to potential and actual water contamination from natural gas drilling operations utilizing hydraulic fracturing from 2008 to present. Please include information regarding any violations of applicable regulations, any water testing done and the results of such tests, and any fine or punishment imposed.

The DEP Office of Oil and Gas is unaware of any confirmed cases of water contamination relating specifically to hydraulic fracturing. However, we have had situations involving surface activities at natural gas drilling operations that have led to potential or actual water contamination. Attached is a list of notices of violation (novs) associated with these operations, exclusive of pipeline activities, along with the associated penalties. Please note that not all novs will have associated penalties and some have penalties that have not yet been assessed.

> *Regarding water analysis, in some cases, samples were taken and analysis done to verify stream conditions associated with the incident. These analyses are currently in hard copy files. As discussed with Mr. Burke, we have not included those analyses in this correspondence, but rather, we have provided an example for you to review. Because the amount of information will vary for each of the violations, we would need considerable time to copy all of the information. If you desire to receive a copy of all the analyses for each of the violations, please let us know.*

Again, thank you for the opportunity to provide this information. If we can be of further assistance, please feel free to contact me.

Sincerely,

Randy C. Huffman
Cabinet Secretary

RCH/jmc

Attachment

	PERMIT_ID	VIOLATION_CODE *	VIOLATION_DATE	ASSESSED PENALTY
1	3906066	22-6-7	5/28/2008	
2	1705651	22-6-7	6/28/2008	$3,750.00
3	1705513	22-6-7	7/31/2008	
4	3906102	22-6-7(b)(1)	8/7/2008	
5	10302334	22-6-7	8/12/2008	
6	1705702	22-6-7(b)(1)	8/19/2008	
7	1705381	22-6-7	9/19/2008	
8	5901202	22-6-7	11/3/2008	
9	1705643	22-6-7	12/5/2008	
10	10302339	22-6-7(b)(1)	2/5/2009	$1,750.00
11	1705657	22-6-7	2/18/2009	
12	1705640	22-6-7	5/23/2009	
13	3304996	22-6-7(b)(1)	5/28/2009	
15	3906060	22-6-7	6/25/2009	$350.00
16	3304996	22-6-7	6/25/2009	
17	3906155	22-6-7(d)	7/16/2009	
18	3906060	22-6-7	7/21/2009	$4,950.00
19	1705814	22-6-7(b)(1)	9/7/2009	$10,000.00
20	8509742	22-6-7	9/20/2009	
21	3906155	22-6-7(d)	1/12/2010	
22	4303415	22-6-7	1/18/2010	
23	4303415	22-6-7	1/18/2010	
24	3906155	22-6-7(d)	2/11/2010	
25	3906155	22-6-7(d)	2/22/2010	
26	1705879	22-6-7(b)(1)	3/18/2010	$6,105.00
30	10302448	22-6-7	4/15/2010	
31	10302427	22-6-7	4/28/2010	
32	103028	22-6-7	5/21/2010	
34	1705896	22-6-7(b)(1)	8/31/2010	
35	5101320	22-6-7(b)(1)	12/14/2010	
36	9101191	22-6-7	1/10/2011	
37	1705957	22-6-7(b)(1)	1/21/2011	
38	5101328	22-6-7(b)(1)	2/25/2011	
39	3305507	22-6-7(b)(1)	3/21/2011	
40	103149	22-6-7	3/22/2011	
41	103149	22-6-7	3/22/2011	
42	3305480	22-6-7(b)(1)	3/25/2011	
43	1705952	22-6-7(b)(1)	3/29/2011	
44	1705971	22-6-7(b)(1)	3/29/2011	

* ***§22-6-7. Water pollution control permits; powers and duties of the director; penalties.***

(a) In addition to a permit for well work, the director, after public notice and an opportunity for public hearings, may either issue a separate permit, general permit or a permit consolidated with the well work permit for the discharge or disposition of any pollutant or combination of pollutants into waters of this state upon condition that such discharge or disposition meets or will meet all applicable state and federal water quality standards and effluent limitations and all other requirements of the director.

(b) It shall be unlawful for any person conducting activities which are subject to the requirements of this article, unless that person holds a water pollution control permit therefor from the director, which is in full force and effect to:

(1) Allow pollutants or the effluent therefrom, produced by or emanating from any point source, to flow into the water of this state;

(2) Make, cause or permit to be made any outlet, or substantially enlarge or add to the load of any existing outlet, for the discharge of pollutants or the effluent therefrom, into the waters of this state;

(3) Acquire, construct, install, modify or operate a disposal system or part thereof for the direct or indirect discharge or deposit of treated or untreated pollutants or the effluent therefrom, into the waters of this state, or any extension to or addition to such disposal system;

(4) Increase in volume or concentration any pollutants in excess of the discharges or disposition specified or permitted under any existing permit;

(5) Extend, modify or add to any point source, the operation of which would cause an increase in the volume or concentration of any pollutants discharging or flowing into the waters of the state;

(6) Operate any disposal well for the injection or reinjection underground of any pollutant, including, but not limited to, liquids or gassas, or convert any well into such a disposal well or plug or abandon any such disposal well.

(c) Notwithstanding any provision of this article or articles seven, eight, nine or ten of this chapter to the contrary, the director shall have the same powers and duties relating to inspection and enforcement as those granted under article eleven, chapter twenty-two of this code in connection with the issuance of any water pollution control permit or any person required to have such permit.

(d) Any person who violates any provision of this section, any order issued under this section or any permit issued pursuant to this section or any rule of the director relating to water pollution or who willfully or negligently violates any provision of this section or any permit issued pursuant to this section or any rule or order of the director relating to water pollution or who fails or refuses to apply for and obtain a permit or who intentionally misrepresents any material fact in an application, record, report, plan or other document files or required to be maintainad under this section shall be subject to the same penalties for such violations as are provided for in sections twenty-two and twenty-four, article eleven, chapter twenty-two of this code: Provided, That the provisions of section twenty-six, article eleven, chapter twenty-two of this code relating to exceptions to criminal liability shall also apply.

All applications for injunction filed pursuant to section twenty-two, article eleven, chapter twenty-two of the code shall take priority on the docket of the circuit court in which pending, and shell take precedence over all other civil cases.

(e) Any water pollution control permit issued pursuant to this section or any order issued in connection with such permit for the purpose of implementing the "national pollutant discharge elimination system" established under the federal Clean Water Actshall be issued by the chief of the office of water resources of the division in consultation with the chief of the office of oil and gas of the division and shall be appealable to the environmental quality board pursuant to the provisions of section twenty-five, article eleven, chapter twenty-two and section seven, article one, chapter twenty-two-b of this code.

	PERMIT_ID	VIOLATION_CODE*	VIOLATION_DATE	ASSESSED PENALTY
1	1705389	35-4-16.4	7/8/2008	
2	10302423	35-4-16.4.c	5/14/2009	
5	3305507	35-4-16.5.a	3/21/2011	$15,000.00
6	3305507	35-4-16.3	3/21/2011	(Included in previous Order)
7	3305480	35-4-16.3	3/25/2011	
8	3305480	35-4-16.5	3/25/2011	
9	1705929	35-4-16.4.d	3/29/2011	
10	1705952	35-4-16.4.c	3/29/2011	
11	1705952	35-4-16.4.a	3/29/2011	
12	1705971	35-4-16.4.c	3/29/2011	
13	1705971	35-4-16.4.a	3/29/2011	
14	1705929	35-4-16.4.a	3/29/2011	

*

35-4-1. General.

1.1. Scope. -- This rule shall govern and apply to proceedings under W. Va. Code §22-6-1, et seq., related to oil and gas wells and other wells. Certain portions of this series shall govern and apply to W. Va. Code §22-12-1, et seq. related to groundwater protection and to W. Va. Code §22-10-1, et seq. related to abandoned wells.

§35-4-16. Reclamation

16.3. Drilling Sites -- Drilling sites shall be constructed and maintained to prevent surface run-off carrying excessive sedimentation from the site, to confine all materials leaked or spilled as a result of drilling operations to the drilling site, and to prevent excess sedimentation by not placing in any stream any material moved or cut. Upon the plugging of a non-productive well, whether as a continuous operation with other permitted well work or otherwise, all cementing and other waste materials resulting therefrom shall be retained on the drilling site.

16.4. Wastewater Pits and Freshwater Impoundments -- All field constructed wastewater pits and freshwater impoundments shall meet the following minimum requirements:

16.4.a. All pits and impoundments shall be constructed and maintained so as to prevent seepage, leakage or overflows and to maintain their integrity.

16.4.c. All pits and impoundments shall have adequate freeboard to prevent overflow, and in no case shall the freeboard be less than approximately two (2) feet. When an operator is unable to maintain adequate freeboard to prevent overflow, the operator shall notify the district inspector and an additional pit (or alternative overflow facility) shall be constructed under the supervision of the Chief. The additional pit or alternative overflow facility shall also meet the requirements specified in this subsection (16.4).

16.4.d. All pits and impoundments shall have an impermeable synthetic liner to prevent seepage or leakage, except those pits and impoundments deemed to be suitable to prevent seepage or leakage based on soil analyses from the operator and standards developed and certified by a registered professional engineer and approved by the Office. Before deeming pits suitable to prevent seepage or leakage without a synthetic liner, the Chief shall notify the surface owner that the surface owner is entitled to receive notice of the application for the well work permit and that the operator has requested that the pit be deemed suitable to prevent seepage or leakage without a synthetic liner. If the surface owner objects, the Chief shall hold a hearing pursuant to article five, chapter twenty-nine-A of the Code of West Virginia before determining that the pit is suitable to prevent seepage or leakage. All such liners shall be installed in such a manner as to protect the structural integrity of both pit or impoundment and liner.

16.5. Surface and Underground Water Pollution.

16.5.a. Before commencing to drill any well for oil and gas, the well owner or operator shall make proper and adequate provision to prevent surface and underground water pollution.

VIOLATION NO.: 8502 DATE: March 25, 2011

FORM VI 27 API NO.: 47-33-05480
(REV 3-2007)

STATE OF WEST VIRGINIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
OFFICE OF OIL AND GAS

NOTICE OF VIOLATION

FARM NAME: Cather, H. Dotson – Trustee WELL NO.: Goff 9HM
DISTRICT: Coal COUNTY: Harrison

TO: PDC Mountaineer LLC
ADDRESS: PO Box 26
120 Genesis Blvd
Bridgeport, WV 26330

DESIGNATED AGENT: Gary W. Fridley
ADDRESS: PO Box 26
120 Genesis Blvd
Bridgeport, WV 26330

FINDING:

The Office of Oil and Gas hereby finds that PDC Mountaineer LLC ("PDC") is in violation of W. Va. Code § 22-6-7(b)(1) for well API # 47-33-05480 for allowing pollutants or the effluent therefrom, produced or emanating from any point source, to flow into the water of this State.

A line containing and transporting completion fluids failed and resulted in discharge of pollutants on to the ground and into the waters of this State.

ORDER:

To abate this violation, PDC must:

1. Immediately contain and remove any pollutants in the surface waters around the well site, and submit a proposal for surface water sampling, including plans for containment and removal of any pollutants found;
2. ~~Submit a proposal for testing and monitoring all water wells within a two thousand foot~~ (2,000 ft) radius of the well pad. If no such water well(s) exists, the proposal shall include alternate methods for groundwater testing and monitoring; and
3. Submit a proposal for soil sampling and remediation to remove and dispose of any contaminated soil from the pad.

The Office of Oil and Gas grants PDC seven (7) days, or until April 1, 2011, to abate this violation.

Under W. Va. Code § 22-6-4(a), PDC may apply for annulment or revision of this finding/order within fifteen (15) days.

SIGNED /s/ Tristan Jenkins Tristan Jenkins
TITLE: Inspector
TELEPHONE: (304) 552-3874

ADDRESS: PO Box 4274
Clarksburg, WV 26302

UNTIL THE SUPERVISING OIL AND GAS INSPECTOR ISSUING THIS NOTICE RECEIVES A CALL FROM YOU (THE OPERATOR) STATING THIS VIOLATION IS ABATED, IT WILL BE ASSUMED THAT THE VIOLATION REMAINS UNABATED.

VIOLATION NO.: 8503 DATE: March 25, 2011

FORM VI 27 API NO.: 47-33-05480
(REV 3-2007)

STATE OF WEST VIRGINIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
OFFICE OF OIL AND GAS

NOTICE OF VIOLATION

FARM NAME: Cather, H. Dotson – Trustee WELL NO.: Goff 9HM
DISTRICT: Coal COUNTY: Harrison

TO: PDC Mountaineer LLC
ADDRESS: PO Box 26
120 Genesis Blvd
Bridgeport, WV 26330

DESIGNATED AGENT: Gary W. Fridley
ADDRESS: PO Box 26
120 Genesis Blvd
Bridgeport, WV 26330

FINDING:

The Office of Oil and Gas hereby finds that PDC Mountaineer LLC ("PDC") is in violation of 35 CSR § 4-16.3 for well API # 47-33-05480 for failing to construct or maintain a drilling site to confine all materials leaked or spilled as a result of drilling operations.

A line containing and transporting completion fluids failed and resulted in a discharge of pollutants on to the ground and into the waters of this State.

ORDER:

To abate this violation, PDC must install berms and/or other secondary containment devices around the location.

The Office of Oil and Gas grants PDC seven (7) days, or until April 1, 2011, to abate this violation.

Under W. Va. Code § 22-6-4(a), PDC may apply for annulment or revision of this finding/order within fifteen (15) days.

SIGNED /s/ Tristan Jenkins Tristan Jenkins
TITLE: Inspector
TELEPHONE: (304) 552-3874

ADDRESS: PO Box 4274
Clarksburg, WV 26302

UNTIL THE SUPERVISING OIL AND GAS INSPECTOR ISSUING THIS NOTICE RECEIVES A CALL FROM YOU (THE OPERATOR) STATING THIS VIOLATION IS ABATED, IT WILL BE ASSUMED THAT THE VIOLATION REMAINS UNABATED.

VIOLATION NO.: 8504 DATE: March 25, 2011

FORM VI 27 API NO.: 47-33-05480
(REV 3-2007)

STATE OF WEST VIRGINIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
OFFICE OF OIL AND GAS

NOTICE OF VIOLATION

FARM NAME: Cather, H. Dotson – Trustee WELL NO.: Goff 9HM
DISTRICT: Coal COUNTY: Harrison

TO:	PDC Mountaineer LLC	DESIGNATED AGENT:	Gary W. Fridley
ADDRESS:	PO Box 26 120 Genesis Blvd Bridgeport, WV 26330	ADDRESS:	PO Box 26 120 Genesis Blvd Bridgeport, WV 26330

FINDING:

The Office of Oil and Gas hereby finds that PDC Mountaineer LLC ("PDC") is in violation of 35 CSR § 4-16.5.a for well API # 47-33-05480 for failing to make proper and adequate provision to prevent surface and underground water pollution.

A line containing and transporting completion fluids failed and resulted in a discharge of pollutants on to the ground and into the waters of this State.

ORDER:

To abate this violation, PDC must develop, submit to the Office of Oil and Gas for approval, and implement a spill prevention plan.

The Office of Oil and Gas grants PDC seven (7) days, or until April 1, 2011, to abate this violation.

Under W. Va. Code § 22-6-4(a), PDC may apply for annulment or revision of this finding/order within fifteen (15) days.

SIGNED /s/ Tristan Jenkins Tristan Jenkins ADDRESS: PO Box 4274
TITLE: Inspector Clarksburg, WV 26302
TELEPHONE: (304) 552-3874

UNTIL THE SUPERVISING OIL AND GAS INSPECTOR ISSUING THIS NOTICE RECEIVES A CALL FROM YOU (THE OPERATOR) STATING THIS VIOLATION IS ABATED, IT WILL BE ASSUMED THAT THE VIOLATION REMAINS UNABATED.

PDC MOUNTAINEER

PDC Mountaineer, LLC
120 Genesis Boulevard, PO Box 26
Bridgeport, WV 26330

304-842-3597
304-808-0913 (fax)

April 8, 2011

Tristan Jenkins
Oil and Gas Inspector
West Virginia Department of Environmental Protection
P.O. Box 4274
Clarksburg, WV 26302

Re: Abatement of NOV – 8502- violation of W.Va. Code 22-6-7(b)(1) for well API # 47-33-05480

Mr. Jenkins:

PDC Mountaineer, LLC (PDC) has contracted Ryan Environmental Inc. (RE) to assist with guidance in accordance with Violation No. 8502. We are addressing abatement of NOV's as per your outline of direction in that order:

To abate NOV's 8502

1. Immediately contain and remove any pollutants in the surface waters around the well site, and submit a proposal for surface water sampling, including plans for containment and removal of any pollutants found;

   RESPONSE: Ryan Environmental responded immediately to the site upon notification of the release and assisted PDC in managing and containing the released fluids on site and into the stream. The release occurred on a hillside and the fluid release flowed down to a containment pond. The containment pond overflowed to the un-named tributary of Davisson Run. The release was immediately stopped and fluid was pumped from the containment pond to allow free-board space. Underflow dams and absorbent booms were placed along the course of the un-named tributary and Davisson Run ahead of a point where Davisson Run enters the West Fork River. A high volume vacuum truck was used to extract fluids from the containment areas. The site was maintained on Thursday 3/24/11 (the date of the release), all night long and monitored regularly throughout the weekend and Monday 3/28/11. Surface water was sampled on 3/25/11. Samples were collected of the actual released flow-back water then other samples were collected from: (1) the unnamed tributary (2) Up-stream Davisson Run prior to where the contaminated un-named tributary entered (3) Up-stream of the West Fork –above where Davisson Run enters (4) Down-stream West Fork –below where Davisson Run enters. Samples were analyzed by Reliance Laboratories, Inc. of Bridgeport, WV and were analyzed with comparison to the National Primary and Secondary Drinking Water Standards reference as per published on the US EPA website.

Analytical results are attached to this letter in chart format to provide a comparison of the results to the applicable standards.

2. Submit a proposal for testing and monitoring all water wells within a two thousand foot (2000 ft.) radius of the well pad. If no such water well(s) exists, the proposal shall include alternate methods for groundwater testing and monitoring;

   RESPONSE: Initially it does not appear that any water wells exist within a 2000 ft. radius of the release. Very wet site conditions due to seasonal rain and snow melt left the surface area very saturated and it is believed that fluids did not penetrate to the level of groundwater. Monitoring wells need not be installed due to lack of contamination however springs and pond where cattle may drink will be tested. The same references as listed in the previous section for potential contaminant analysis will be used.

3. Submit a proposal for soil sampling and remediation to remove and dispose of any contaminated soil from the pad.

   RESPONSE: Two soil samples were collected on 3/25/11 and analytical results are attached to this letter. One sample was collected up-gradient of the site pad and release point to establish background conditions. A second sample was composited from biased sampling points along the flow path of the released fluids across the surface. Both samples were collected from surface soils. The samples were analyzed with comparison to the guidelines that are related to Industrial Soil for "Contaminants of Concern (COC's)" and utilizing WV De Minimis Level reference as per published 60CSR3 Table 60-3B and draft Supplemental Guidance on TPH. Analytical results will be reviewed with you and a determination will be made regarding potential need for additional sampling or a need for removal, transport and disposal of any contaminated soil.

   Analytical results are attached to this letter in chart format to provide a comparison of the results to the applicable standards.

Thank you for cooperation in assisting us to effect abatement at our Goff 9HM site in Harrison County, West Virginia. If you have any questions regarding this response, please advise.

Sincerely,

Larry E. "Eddie" Carder
EHS Field Coordinator
PDC Mountaineer, LLC

PDCM
GOFF 9HM
3/24/2011

TCLP METALS (mg/L)	NPDWR	oo1	oo2	oo3	oo4	Flowback water
Arsenic	0.01	ND	ND	ND	ND	**0.16**
Barium	2	0.11	0.07	0.19	0.08	**89.7**
Cadmium	0.005	ND	ND	ND	ND	ND
Lead	0.015	ND	ND	0.008	ND	**0.04**
Selenium	0.05	ND	ND	ND	ND	**1.21**
Silver	0.1	ND	ND	ND	ND	ND
Mercury	0.002	ND	ND	ND	ND	ND

TOTAL METALS (mg/L)	NPDWR	oo1	oo2	oo3	oo4	Flowback water
Arsenic	0.01	ND	ND	ND	ND	ND
Barium	2	0.11	0.07	0.19	0.08	**89.7**
Berylium	0.004	ND	ND	ND	ND	ND
Boron	*	0.01	ND	ND	ND	0.39
Calcium	*	92.4	159	64	209	1,270
Chromium	0.1	0.01	ND	ND	ND	0.05
Cyanide	0.2	ND	ND	ND	ND	ND
Lithium	0.73	ND	ND	ND	ND	**20.2**
Manganese	0.05	**0.1**	**0.07**	**0.93**	**0.19**	**1.26**
Sodium	*	13.1	10	14.6	17	5,020
Strontium	0.0022	0.29	0.53	0.25	0.63	252

mg/L	NPDWR	oo1	oo2	oo3	oo4	Flowback water
TPH-GRO	*	ND	ND	ND	ND	507
TPH-DRO	*	ND	ND	ND	ND	ND
TPH-ORO	*	ND	ND	ND	ND	673

mg/L	NPDWR	oo1	oo2	oo3	oo4	Flowback water
Benzene	0.005	ND	ND	ND	ND	ND
Toluene	1	ND	ND	ND	ND	ND
Ethylbenzene	0.7	ND	ND	ND	ND	ND
Xylene	10	ND	ND	ND	ND	ND

mg/L	NPDWR	oo1	oo2	oo3	oo4	Flowback water
Chloride	250	9.5	7	6.5	11	**13,996**
TDS	500	186	428	162	**510**	**28,380**
TSS	100	20	ND	234	26	**150**
Chromium VI	*	ND	ND	ND	ND	ND

NPDWR means National Primary Drinking Water Regulations
Note: Bold indicates those values that are above State Action Limits
ND Means Not Detected
* Value is not available

PDCM
GOFF 9HM
3/24/2011

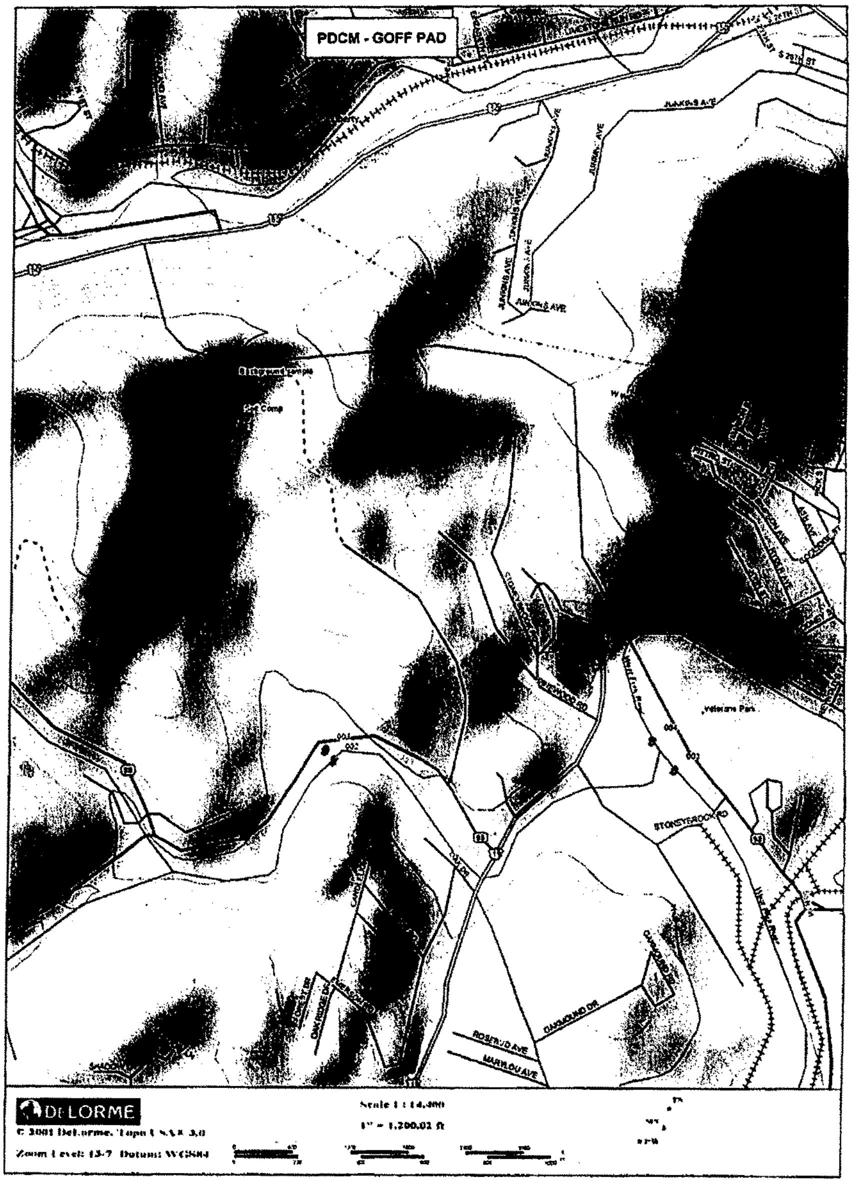
TCLP METALS (mg/Kg)	WV De Minimis Industrial Levels	Composite soil	Background Composite
Arsenic	27	ND	ND
Barium	290,000	1.24	1.14
Cadmium	1,000	0.03	0.03
Lead	1,000	0.05	0.04
Selenium	10,000	ND	ND
Silver	10,000	ND	ND
Mercury	610	ND	ND

TOTAL METALS (mg/Kg)		Composite soil	Background Composite
Arsenic	27	ND	ND
Barium	290,000	1.24	1.14
Berylium	*	ND	ND
Boron	Indicator	0.09	ND
Calcium	Indicator	704	496
Chromium	1,000,000	0.03	0.04
Cyanide	35	ND	ND
Lithium	41,000	0.06	ND
Manganese	48,000	1.62	0.25
Sodium	Indicator	944	854
Strontium	1,000,000		

mg/Kg		Composite soil	Background Composite
TPH-GRO	6,600	24.9	7.49
TPH-DRO	8,300	68.5	ND
TPH-ORO	9,000	ND	ND
Benzene	15	ND	ND
Toluene	260	ND	ND
Ethylbenzene	110	ND	ND
Xylene	100	ND	ND

mg/Kg		Composite soil	Background Composite
Chloride	250	**980**	ND
Chromium VI	4,500	0.003	ND

NPDWR means National Primary Drinking Water Regulations
Note: Bold indicates those values that are above State Action Limits
ND Means Not Detected
* Value is not available


PDCM - GOFF PAD
JUNKINS AVE
STONEYBROOK RD
Veterans Park
ROSEWOOD AVE
MARYLOU AVE
OAKMOUND DR
DELORME
© 2001 DeLorme. Topo USA® 3.0
Zoom Level: 13-7 Datum: WGS84
Scale 1 : 14,400
1" = 1,200.02 ft

RELIANCE LABORATORIES, INC.

ENVIRONMENTAL ANALYSTS AND CONSULTANTS

BRIDGEPORT, WV www.RelianceLabs.net MARTINSBURG, WV

Certifications: WV Department of Health #: 00354, 00433 | WV Department of Environmental Protection #: 158, 181
MD Department of Environment #: 338, 337 | US Environmental Protection Agency #: WV00042, WV00901

LABORATORY REPORT SUMMARY

Client: C00356

Friday, April 01, 2011

RYAN ENVIRONMENTAL
ROUTE 4 BOX 260
BRIDGEPORT WV 26330-

Total Number of Pages: 17
(Not Including C.O.C.)
Page 1 of 17

Lab ID	Sample ID	Sample ID 2	Sample Date
157264-2011-W	001	PDCM-GOFF	3/25/2011
157265-2011-W	002	PDCM-GOFF	3/25/2011
157266-2011-W	003	PDCM-GOFF	3/25/2011
157267-2011-W	004	PDCM-GOFF	3/25/2011
157269-2011-W	FLOWBACK	PDCM-GOFF	3/25/2011
157270-2011-S	FLOWBACK COMP SOIL	PDCM-GOFF	3/25/2011
157271-2011-S	BACKGROUND SOIL	PDCM-GOFF	3/25/2011

The enclosed results have been analyzed according to the referenced method and SOP. Any deviations to the method have been noted on the report. Unless otherwise noted, all results have been verified to meet quality control requirements of the method. This report may not be reproduced, except in full, without written approval of Reliance Laboratories, Inc.

Report Reviewed By:

RLI 001

2044 MEADOWBROOK ROAD | P.O. BOX 4657 | BRIDGEPORT, WV 26330 | VOICE: 304-842-5285 | FAX: 304-842-5351
RIDGEFIELD BUSINESS CENTER | 28 CRIMSON CIRCLE | MARTINSBURG, WV 25403 | VOICE: 304-596-2084 | FAX: 304-596-2086
EMAIL: RELIANCELABS@WVDSL.NET | WEB: WWW.RELIANCELABS.NET

RELIANCE LABORATORIES, INC.

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RYAN ENVIRONMENTAL
ROUTE 4 BOX 260

BRIDGEPORT, WV 26330-

Friday, April 01, 2011
Page 2 of 17

Lab Number: 157264-2011-W. **Sample ID:** 001
PDCM-GOFF

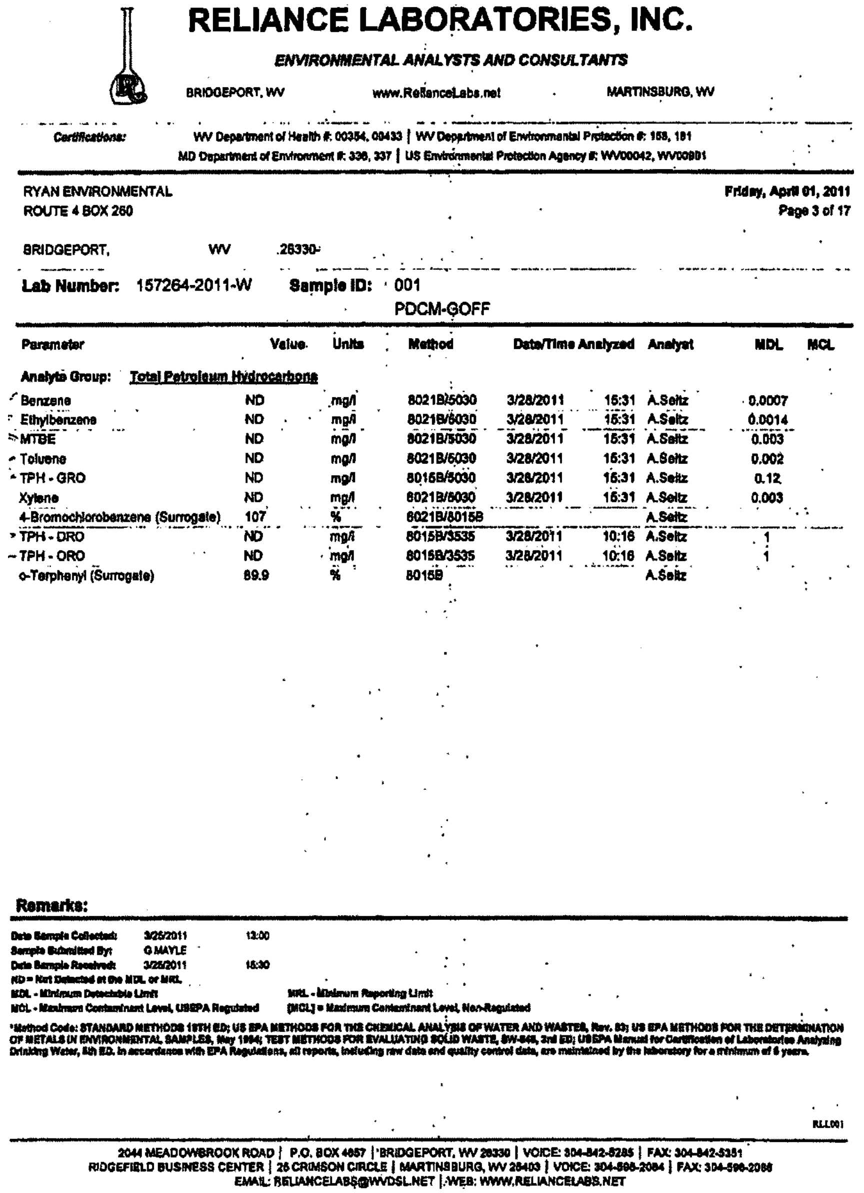
Parameter	Value	Units	Method	Date/Time Analyzed	Analyst	MDL	MCL
Analyte Group: Inorganics							
Total Cyanide	ND	mg/l	SM4500CND	3/28/2011 11:30	A.Seltz	0.004	
Total Chloride	9.50	mg/l	SM 4500CLB	3/28/2011 15:15	M.Coffman	3.33	
Hexavalent Chromium	ND	mg/l	SM3500-CR-D	3/25/2011 16:45	M.Coffman	0.002	
Total Dissolved Solids	186	mg/l	SM 2540C.	3/28/2011 8:55	C.Parker	10	
Total Suspended Solids	20	mg/l	SM2540D	3/28/2011 8:55	C.Parker	4	
Total Arsenic	ND	mg/l	EPA 200.8	3/31/2011 12:45	T.Hanshaw	0.001	
Total Barium	0.11	mg/l	EPA 200.8	3/31/2011 12:45	T.Hanshaw	0.0015	
Total Beryllium	ND	mg/l	EPA 200.8	3/31/2011 12:45	T.Hanshaw	0.0005	
Total Boron	0.01	mg/l	EPA 200.8	3/31/2011 12:45	T.Hanshaw	0.003	
Total Cadmium	ND	mg/l	EPA 200.8	3/31/2011 12:45	T.Hanshaw	0.0002	
Total Calcium	92.4	mg/l	EPA 200.8	3/31/2011 12:45	T.Hanshaw	0.01	
Total Chromium	0.01	mg/l	EPA 200.8	3/31/2011 12:45	T.Hanshaw	0.001	
Total Lead	ND	mg/l	EPA 200.8	3/31/2011 12:45	T.Hanshaw	0.0005	
Total Lithium	ND	mg/l	EPA 200.7	4/1/2011 11:09	T.Hanshaw	0.1	
Total Manganese	0.10	mg/l	EPA 200.8	3/31/2011 12:45	T.Hanshaw	0.002	
Total Mercury	ND	mg/l	EPA 200.8	3/31/2011 12:45	T.Hanshaw	0.0001	
Total Selenium	ND	mg/l	EPA 200.8	3/31/2011 12:45	T.Hanshaw	0.001	
Total Silver	ND	mg/l	EPA 200.8	3/31/2011 12:45	T.Hanshaw	0.0002	
Total Sodium	13.1	mg/l	EPA 200.8	3/31/2011 12:45	T.Hanshaw	0.01	
Total Strontium	0.29	mg/l	EPA 200.8	4/1/2011 11:51	T.Hanshaw	0.01	

Remarks:

Date Sample Collected:	3/25/2011	13:00
Sample Submitted By:	G MAYLE	
Date Sample Received:	3/25/2011	15:30

ND = Not Detected at the MDL or MRL
MDL - Minimum Detectable Limit MRL - Minimum Reporting Limit
MCL - Maximum Contaminant Level, USEPA Regulated [MCL] = Maximum Contaminant Level, Non-Regulated

*Method Code: STANDARD METHODS 19TH ED; US EPA METHODS FOR THE CHEMICAL ANALYSIS OF WATER AND WASTES, Rev. 83; US EPA METHODS FOR THE DETERMINATION OF METALS IN ENVIRONMENTAL SAMPLES, May 1994; TEST METHODS FOR EVALUATING SOLID WASTE, SW-846, 3rd ED; USEPA Manual for Certification of Laboratories Analyzing Drinking Water, 5th ED. In accordance with EPA Regulations, all reports, including raw data and quality control data, are maintained by the laboratory for a minimum of 5 years.



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MD Department of Environment #: 336, 337 | US Environmental Protection Agency #: WV00042, WV00901

RYAN ENVIRONMENTAL
ROUTE 4 BOX 260

BRIDGEPORT, WV 26330-

Friday, April 01, 2011
Page 3 of 17

Lab Number: 157264-2011-W **Sample ID:** 001
PDCM-GOFF

Parameter	Value	Units	Method	Date/Time Analyzed	Analyst	MDL	MCL
Analyte Group: Total Petroleum Hydrocarbons							
Benzene	ND	mg/l	8021B/5030	3/28/2011 15:31	A.Seitz	0.0007	
Ethylbenzene	ND	mg/l	8021B/5030	3/28/2011 15:31	A.Seitz	0.0014	
MTBE	ND	mg/l	8021B/5030	3/28/2011 15:31	A.Seitz	0.003	
Toluene	ND	mg/l	8021B/5030	3/28/2011 15:31	A.Seitz	0.002	
TPH - GRO	ND	mg/l	8015B/5030	3/28/2011 15:31	A.Seitz	0.12	
Xylene	ND	mg/l	8021B/5030	3/28/2011 15:31	A.Seitz	0.003	
4-Bromochlorobenzene (Surrogate)	107	%	8021B/8015B		A.Seitz		
TPH - DRO	ND	mg/l	8015B/3535	3/28/2011 10:16	A.Seitz	1	
TPH - ORO	ND	mg/l	8015B/3535	3/28/2011 10:16	A.Seitz	1	
o-Terphenyl (Surrogate)	89.9	%	8015B		A.Seitz		

Remarks:

Date Sample Collected:	3/25/2011	13:00
Sample Submitted By:	G MAYLE	
Date Sample Received:	3/25/2011	15:30

ND = Not Detected at the MDL or MRL
MDL - Minimum Detectable Limit MRL - Minimum Reporting Limit
MCL - Maximum Contaminant Level, USEPA Regulated [MCL] = Maximum Contaminant Level, Non-Regulated

*Method Code: STANDARD METHODS 18TH ED; US EPA METHODS FOR THE CHEMICAL ANALYSIS OF WATER AND WASTES, Rev. 83; US EPA METHODS FOR THE DETERMINATION OF METALS IN ENVIRONMENTAL SAMPLES, May 1994; TEST METHODS FOR EVALUATING SOLID WASTE, SW-846, 3rd ED; USEPA Manual for Certification of Laboratories Analyzing Drinking Water, 5th ED. In accordance with EPA Regulations, all reports, including raw data and quality control data, are maintained by the laboratory for a minimum of 5 years.

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RYAN ENVIRONMENTAL
ROUTE 4 BOX 260

BRIDGEPORT, WV 26330-

Friday, April 01, 2011
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Lab Number: 157265-2011-W **Sample ID:** 002
PDCM-GOFF

Parameter	**Value**	**Units**	**Method**	**Date/Time Analyzed**		**Analyst**	**MDL**	**MCL**
Analyte Group: **Inorganics**								
Total Cyanide	ND	mg/l	SM4500CND	3/28/2011	11:30	A.Seitz	0.004	
Total Chloride	7.00	mg/l	SM 4500CLB	3/28/2011	15:15	M.Coffman	3.33	
Hexavalent Chromium	ND	mg/l	SM3500-CR-D	3/25/2011	16:45	M.Coffman	0.002	
Total Dissolved Solids	428	mg/l	SM 2540C	3/28/2011	8:55	C.Parker	10	
Total Suspended Solids	ND	mg/l	SM2540D	3/28/2011	8:55	C.Parker	4	
Total Arsenic	ND	mg/l	EPA 200.8	3/31/2011	12:51	T.Hanshaw	0.001	
Total Barium	0.07	mg/l	EPA 200.8	3/31/2011	12:51	T.Hanshaw	0.0015	
Total Beryllium	ND	mg/l	EPA 200.8	3/31/2011	12:51	T.Hanshaw	0.0005	
Total Boron	ND	mg/l	EPA 200.8	3/31/2011	12:51	T.Hanshaw	0.003	
Total Cadmium	ND	mg/l	EPA 200.8	3/31/2011	12:51	T.Hanshaw	0.0002	
Total Calcium	159	mg/l	EPA 200.8	3/31/2011	12:51	T.Hanshaw	0.01	
Total Chromium	ND	mg/l	EPA 200.8	3/31/2011	12:51	T.Hanshaw	0.001	
Total Lead	ND	mg/l	EPA 200.8	3/31/2011	12:51	T.Hanshaw	0.0005	
Total Lithium	ND	mg/l	EPA 200.7	4/1/2011	11:11	T.Hanshaw	0.1	
Total Manganese	0.07	mg/l	EPA 200.8	3/31/2011	12:51	T.Hanshaw	0.002	
Total Mercury	ND	mg/l	EPA 200.8	3/31/2011	12:51	T.Hanshaw	0.0001	
Total Selenium	ND	mg/l	EPA 200.8	3/31/2011	12:51	T.Hanshaw	0.001	
Total Silver	ND	mg/l	EPA 200.8	3/31/2011	12:51	T.Hanshaw	0.0002	
Total Sodium	10.0	mg/l	EPA 200.8	3/31/2011	12:51	T.Hanshaw	0.01	
Total Strontium	0.53	mg/l	EPA 200.8	4/1/2011	11:53	T.Hanshaw	0.01	

Remarks:

Date Sample Collected:	3/25/2011	13:20
Sample Submitted By:	G MAYLE	
Date Sample Received:	3/25/2011	15:30

ND = Not Detected at the MDL or MRL

MDL - Minimum Detectable Limit **MRL - Minimum Reporting Limit**

MCL - Maximum Contaminant Level, USEPA Regulated **[MCL] = Maximum Contaminant Level, Non-Regulated**

***Method Code: STANDARD METHODS 19TH ED; US EPA METHODS FOR THE CHEMICAL ANALYSIS OF WATER AND WASTES, Rev. 83; US EPA METHODS FOR THE DETERMINATION OF METALS IN ENVIRONMENTAL SAMPLES, May 1994; TEST METHODS FOR EVALUATING SOLID WASTE, SW-846, 3rd ED; USEPA Manual for Certification of Laboratories Analyzing Drinking Water, 5th ED. In accordance with EPA Regulations, all reports, including raw data and quality control data, are maintained by the laboratory for a minimum of 5 years.**

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MD Department of Environment #: 338, 337 | US Environmental Protection Agency #: WV00042, WV00901

RYAN ENVIRONMENTAL
ROUTE 4 BOX 260

BRIDGEPORT, WV 26330-

Friday, April 01, 2011
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Lab Number: 157265-2011-W **Sample ID:** 002
PDCM-GOFF

Parameter	**Value**	**Units**	**Method**	**Date/Time Analyzed**		**Analyst**	**MDL**	**MCL**
Analyte Group: **Total Petroleum Hydrocarbons**								
Benzene	ND	mg/l	8021B/5030	3/30/2011	10:09	A.Seitz	0.0007	
Ethylbenzene	ND	mg/l	8021B/5030	3/30/2011	10:09	A.Seitz	0.0014	
MTBE	ND	mg/l	8021B/5030	3/30/2011	10:09	A.Seitz	0.003	
Toluene	ND	mg/l	8021B/5030	3/30/2011	10:09	A.Seitz	0.002	
TPH - GRO	ND	mg/l	8015B/5030	3/30/2011	10:09	A.Seitz	0.12	
Xylene	ND	mg/l	8021B/5030	3/30/2011	10:09	A.Seitz	0.003	
4-Bromochlorobenzene (Surrogate)	94.4	%	8021B/8015B			A.Seitz		
TPH - DRO	ND	mg/l	8015B/3535	3/28/2011	11:08	A.Seitz	1	
TPH - ORO	ND	mg/l	8015B/3535	3/28/2011	11:08	A.Seitz	1	
o-Terphenyl (Surrogate)	87.4	%	8015B			A.Seitz		

Remarks:

Date Sample Collected:	3/28/2011	13:20
Sample Submitted By:	G MAYLE	
Date Sample Received:	3/28/2011	15:30

ND = Not Detected at the MDL or MRL

MDL - Minimum Detectable Limit
MRL - Minimum Reporting Limit
MCL - Maximum Contaminant Level, USEPA Regulated
[MCL] = Maximum Contaminant Level, Non-Regulated

*Method Code: STANDARD METHODS 18TH ED; US EPA METHODS FOR THE CHEMICAL ANALYSIS OF WATER AND WASTES, Rev. 83; US EPA METHODS FOR THE DETERMINATION OF METALS IN ENVIRONMENTAL SAMPLES, May 1994; TEST METHODS FOR EVALUATING SOLID WASTES, SW-846, 3rd ED; USEPA Manual for Certification of Laboratories Analyzing Drinking Water, 5th ED. In accordance with EPA Regulations, all reports, including raw data and quality control data, are maintained by the laboratory for a minimum of 5 years.

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RYAN ENVIRONMENTAL
ROUTE 4 BOX 260

BRIDGEPORT, WV 26330-

Friday, April 01, 2011
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Lab Number: 157266-2011-W **Sample ID:** 003
PDCM-GOFF

Parameter	Value	Units	Method	Date/Time Analyzed		Analyst	MDL	MCL
Analyte Group: Inorganics								
Total Cyanide	ND	mg/l	SM4500CND	3/28/2011	11:30	A.Seitz	0.004	
Total Chloride	6.60	mg/l	SM 4500CLB	3/28/2011	15:15	M.Coffman	3.33	
Hexavalent Chromium	ND	mg/l	SM3500-CR-D	3/25/2011	16:45	M.Coffman	0.002	
Total Dissolved Solids	162	mg/l	SM 2540C	3/28/2011	8:55	C.Parker	10	
Total Suspended Solids	234	mg/l	SM2540D	3/28/2011	8:55	C.Parker	4	
Total Arsenic	ND	mg/l	EPA 200.8	3/31/2011	12:57	T.Hanshaw	0.001	
Total Barium	0.19	mg/l	EPA 200.8	3/31/2011	12:57	T.Hanshaw	0.0015	
Total Beryllium	ND	mg/l	EPA 200.8	3/31/2011	12:57	T.Hanshaw	0.0005	
Total Boron	ND	mg/l	EPA 200.8	3/31/2011	12:57	T.Hanshaw	0.003	
Total Cadmium	ND	mg/l	EPA 200.8	3/31/2011	12:57	T.Hanshaw	0.0002	
Total Calcium	64.0	mg/l	EPA 200.8	3/31/2011	12:57	T.Hanshaw	0.01	
Total Chromium	ND	mg/l	EPA 200.8	3/31/2011	12:57	T.Hanshaw	0.001	
Total Lead	0.008	mg/l	EPA 200.8	3/31/2011	12:57	T.Hanshaw	0.0005	
Total Lithium	ND	mg/l	EPA 200.7	4/1/2011	11:14	T.Hanshaw	0.1	
Total Manganese	0.93	mg/l	EPA 200.8	3/31/2011	12:57	T.Hanshaw	0.002	
Total Mercury	ND	mg/l	EPA 200.8	3/31/2011	12:57	T.Hanshaw	0.0001	
Total Selenium	ND	mg/l	EPA 200.8	3/31/2011	12:57	T.Hanshaw	0.001	
Total Silver	ND	mg/l	EPA 200.8	3/31/2011	12:57	T.Hanshaw	0.0002	
Total Sodium	14.6	mg/l	EPA 200.8	3/31/2011	12:57	T.Hanshaw	0.01	
Total Strontium	0.25	mg/l	EPA 200.8	4/1/2011	11:55	T.Hanshaw	0.01	

Remarks:

Date Sample Collected:	3/25/2011	14:00
Sample Submitted By:	G MAYLE	
Date Sample Received:	3/25/2011	16:06

ND = Not Detected at the MDL or MRL
MDL - Minimum Detectable Limit MRL - Minimum Reporting Limit
MCL - Maximum Contaminant Level, USEPA Regulated (MCL) = Maximum Contaminant Level, Non-Regulated

*Method Code: STANDARD METHODS 19TH ED; US EPA METHODS FOR THE CHEMICAL ANALYSIS OF WATER AND WASTES, Rev. 83; US EPA METHODS FOR THE DETERMINATION OF METALS IN ENVIRONMENTAL SAMPLES, May 1994; TEST METHODS FOR EVALUATING SOLID WASTE, SW-846, 3rd ED; USEPA Manual for Certification of Laboratories Analyzing Drinking Water, 5th ED. In accordance with EPA Regulations, all reports, including raw data and quality control data, are maintained by the laboratory for a minimum of 5 years.

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RYAN ENVIRONMENTAL
ROUTE 4 BOX 260

BRIDGEPORT, WV 26330-

Friday, April 01, 2011
Page 7 of 17

Lab Number: 157266-2011-W **Sample ID:** 003
PDCM-GOFF

Analyte Group: **Total Petroleum Hydrocarbons**

Parameter	Value	Units	Method	Date/Time Analyzed		Analyst	MDL	MCL
Benzene	ND	mg/l	8021B/5030	3/30/2011	10:58	A.Seitz	0.0007	
Ethylbenzene	ND	mg/l	8021B/5030	3/30/2011	10:58	A.Seitz	0.0014	
MTBE	ND	mg/l	8021B/5030	3/30/2011	10:58	A.Seitz	0.003	
Toluene	ND	mg/l	8021B/5030	3/30/2011	10:58	A.Seitz	0.002	
TPH - GRO	ND	mg/l	8015B/5030	3/30/2011	10:58	A.Seitz	0.12	
Xylene	ND	mg/l	8021B/5030	3/30/2011	10:58	A.Seitz	0.003	
4-Bromochlorobenzene (Surrogate)	94.8	%	8021B/8015B			A.Seitz		
TPH - DRO	ND	mg/l	8015B/3535	3/28/2011	13:12	A.Seitz	1	
TPH - ORO	ND	mg/l	8015B/3535	3/28/2011	13:12	A.Seitz	1	
o-Terphenyl (Surrogate)	80.7	%	8015B			A.Seitz		

Remarks:

Date Sample Collected:	3/25/2011	14:00
Sample Submitted By:	G MAYLE	
Date Sample Received:	3/25/2011	16:06

ND = Not Detected at the MDL or MRL
MDL - Minimum Detectable Limit
MRL - Minimum Reporting Limit
MCL - Maximum Contaminant Level, USEPA Regulated
[MCL] = Maximum Contaminant Level, Non-Regulated

*Method Code: STANDARD METHODS 18TH ED; US EPA METHODS FOR THE CHEMICAL ANALYSIS OF WATER AND WASTES, Rev. 83; US EPA METHODS FOR THE DETERMINATION OF METALS IN ENVIRONMENTAL SAMPLES, May 1994; TEST METHODS FOR EVALUATING SOLID WASTE, SW-846, 3rd ED; USEPA Manual for Certification of Laboratories Analyzing Drinking Water, 5th ED. In accordance with EPA Regulations, all reports, including raw data and quality control data, are maintained by the laboratory for a minimum of 5 years.

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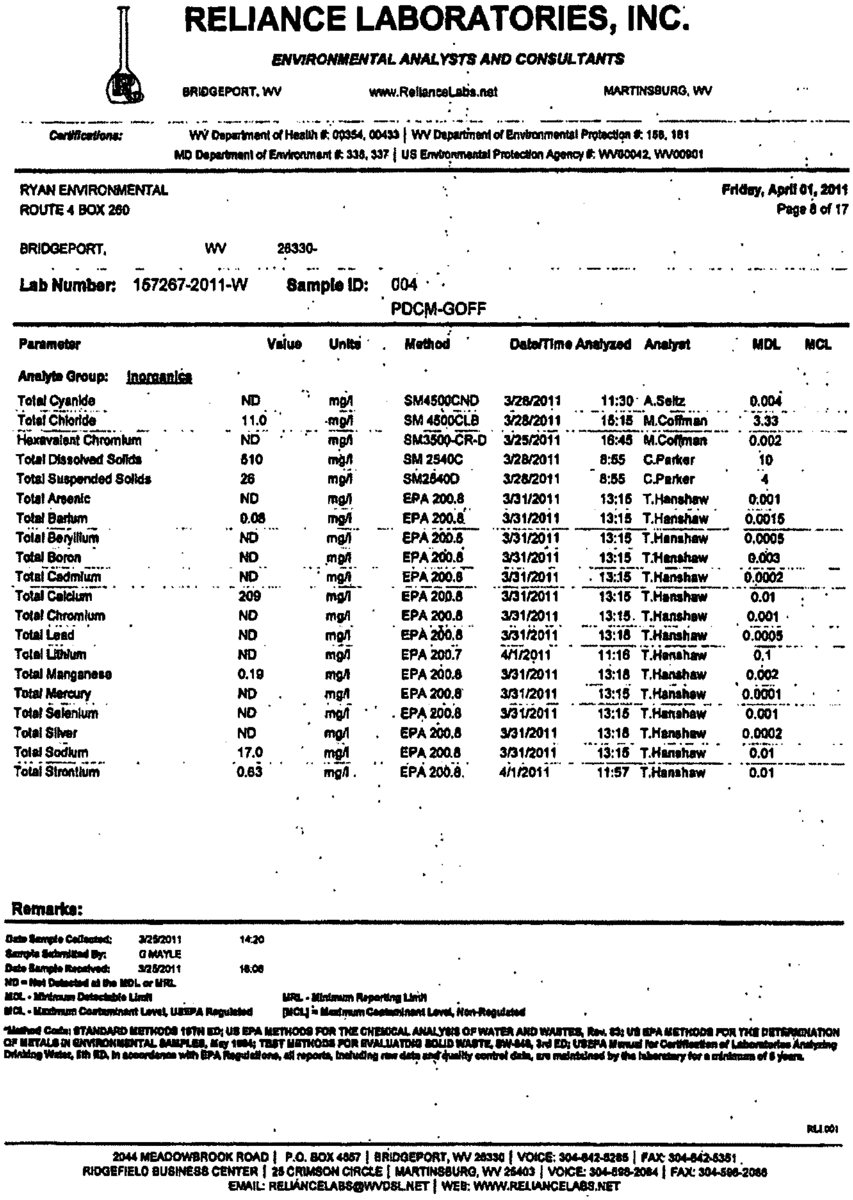

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RYAN ENVIRONMENTAL
ROUTE 4 BOX 260

BRIDGEPORT, WV 26330-

Friday, April 01, 2011
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Lab Number: 157267-2011-W **Sample ID:** 004
PDCM-GOFF

Parameter	Value	Units	Method	Date/Time Analyzed		Analyst	MDL	MCL
Analyte Group: Inorganics								
Total Cyanide	ND	mg/l	SM4500CND	3/28/2011	11:30	A.Seitz	0.004	
Total Chloride	11.0	mg/l	SM 4500CLB	3/28/2011	15:15	M.Coffman	3.33	
Hexavalent Chromium	ND	mg/l	SM3500-CR-D	3/25/2011	16:45	M.Coffman	0.002	
Total Dissolved Solids	510	mg/l	SM 2540C	3/28/2011	8:55	C.Parker	10	
Total Suspended Solids	26	mg/l	SM2540D	3/28/2011	8:55	C.Parker	4	
Total Arsenic	ND	mg/l	EPA 200.8	3/31/2011	13:15	T.Hanshaw	0.001	
Total Barium	0.08	mg/l	EPA 200.8	3/31/2011	13:15	T.Hanshaw	0.0015	
Total Beryllium	ND	mg/l	EPA 200.8	3/31/2011	13:15	T.Hanshaw	0.0005	
Total Boron	ND	mg/l	EPA 200.8	3/31/2011	13:15	T.Hanshaw	0.003	
Total Cadmium	ND	mg/l	EPA 200.8	3/31/2011	13:15	T.Hanshaw	0.0002	
Total Calcium	209	mg/l	EPA 200.8	3/31/2011	13:15	T.Hanshaw	0.01	
Total Chromium	ND	mg/l	EPA 200.8	3/31/2011	13:15	T.Hanshaw	0.001	
Total Lead	ND	mg/l	EPA 200.8	3/31/2011	13:15	T.Hanshaw	0.0005	
Total Lithium	ND	mg/l	EPA 200.7	4/1/2011	11:16	T.Hanshaw	0.1	
Total Manganese	0.19	mg/l	EPA 200.8	3/31/2011	13:15	T.Hanshaw	0.002	
Total Mercury	ND	mg/l	EPA 200.8	3/31/2011	13:15	T.Hanshaw	0.0001	
Total Selenium	ND	mg/l	EPA 200.8	3/31/2011	13:15	T.Hanshaw	0.001	
Total Silver	ND	mg/l	EPA 200.8	3/31/2011	13:15	T.Hanshaw	0.0002	
Total Sodium	17.0	mg/l	EPA 200.8	3/31/2011	13:15	T.Hanshaw	0.01	
Total Strontium	0.63	mg/l	EPA 200.8	4/1/2011	11:57	T.Hanshaw	0.01	

Remarks:

Date Sample Collected: 3/25/2011 14:20
Sample Submitted By: G MAYLE
Date Sample Received: 3/25/2011 16:06
ND = Not Detected at the MDL or MRL
MDL - Minimum Detectable Limit
MRL - Minimum Reporting Limit
MCL - Maximum Contaminant Level, USEPA Regulated
[MCL] = Maximum Contaminant Level, Non-Regulated

*Method Code: STANDARD METHODS 19TH ED; US EPA METHODS FOR THE CHEMICAL ANALYSIS OF WATER AND WASTES, Rev. 83; US EPA METHODS FOR THE DETERMINATION OF METALS IN ENVIRONMENTAL SAMPLES, May 1994; TEST METHODS FOR EVALUATING SOLID WASTE, SW-846, 3rd ED; USEPA Manual for Certification of Laboratories Analyzing Drinking Water, 5th ED. In accordance with EPA Regulations, all reports, including raw data and quality control data, are maintained by the laboratory for a minimum of 5 years.

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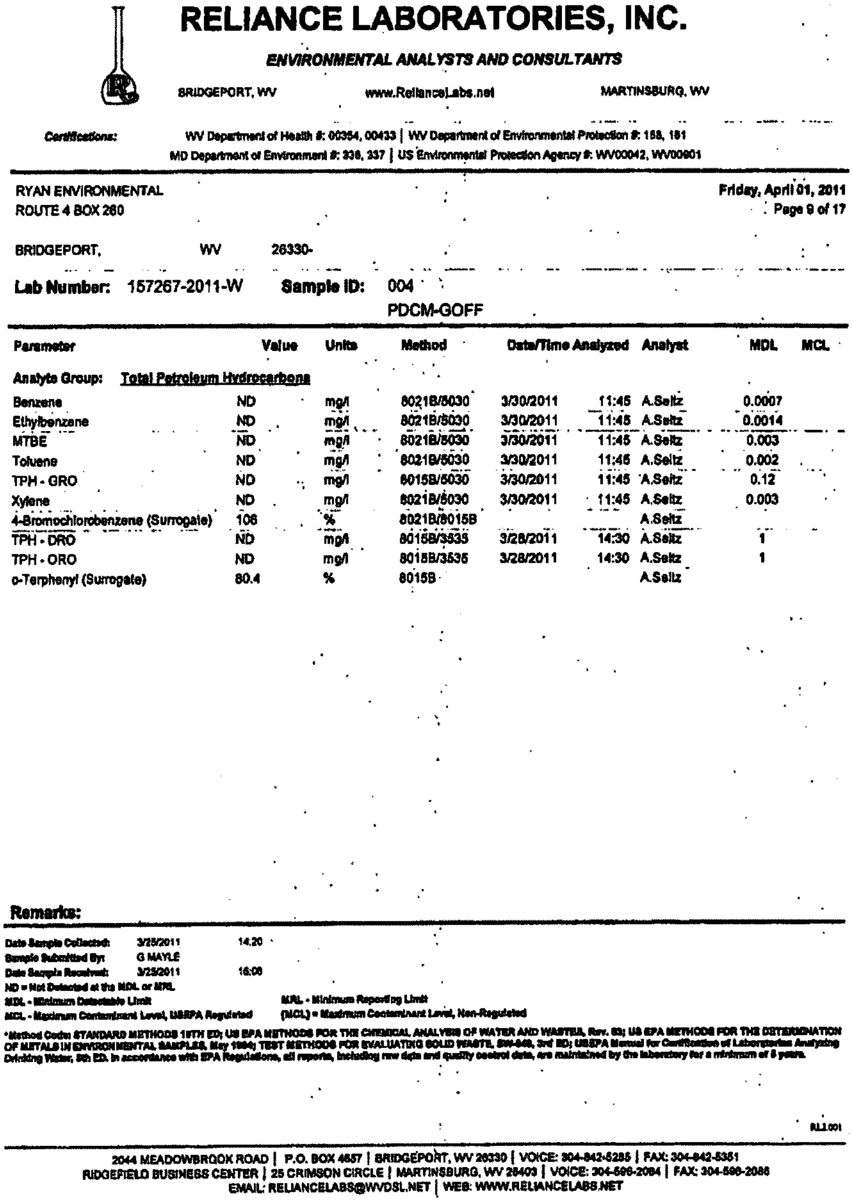

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RYAN ENVIRONMENTAL
ROUTE 4 BOX 260

BRIDGEPORT, WV 26330-

Friday, April 01, 2011
Page 9 of 17

Lab Number: 157267-2011-W **Sample ID:** 004
PDCM-GOFF

Parameter	Value	Units	Method	Date/Time Analyzed		Analyst	MDL	MCL
Analyte Group: Total Petroleum Hydrocarbons								
Benzene	ND	mg/l	8021B/5030	3/30/2011	11:45	A.Seltz	0.0007	
Ethylbenzene	ND	mg/l	8021B/5030	3/30/2011	11:45	A.Seltz	0.0014	
MTBE	ND	mg/l	8021B/5030	3/30/2011	11:45	A.Seltz	0.003	
Toluene	ND	mg/l	8021B/5030	3/30/2011	11:45	A.Seltz	0.002	
TPH - GRO	ND	mg/l	8015B/5030	3/30/2011	11:45	A.Seltz	0.12	
Xylene	ND	mg/l	8021B/5030	3/30/2011	11:45	A.Seltz	0.003	
4-Bromochlorobenzene (Surrogate)	106	%	8021B/8015B			A.Seltz		
TPH - DRO	ND	mg/l	8015B/3535	3/28/2011	14:30	A.Seltz	1	
TPH - ORO	ND	mg/l	8015B/3535	3/28/2011	14:30	A.Seltz	1	
o-Terphenyl (Surrogate)	80.4	%	8015B			A.Seltz		

Remarks:

Date Sample Collected:	3/25/2011	14:20
Sample Submitted By:	G MAYLE	
Date Sample Received:	3/25/2011	16:00

ND = Not Detected at the MDL or MRL
MDL - Minimum Detectable Limit
MRL - Minimum Reporting Limit
MCL - Maximum Contaminant Level, USEPA Regulated
(MCL) = Maximum Contaminant Level, Non-Regulated

*Method Codes: STANDARD METHODS 18TH ED; US EPA METHODS FOR THE CHEMICAL ANALYSIS OF WATER AND WASTES, Rev. 83; US EPA METHODS FOR THE DETERMINATION OF METALS IN ENVIRONMENTAL SAMPLES, May 1994; TEST METHODS FOR EVALUATING SOLID WASTE, SW-846, 3rd ED; USEPA Manual for Certification of Laboratories Analyzing Drinking Water, 5th ED. In accordance with EPA Regulations, all reports, including raw data and quality control data, are maintained by the laboratory for a minimum of 5 years.

RL1001

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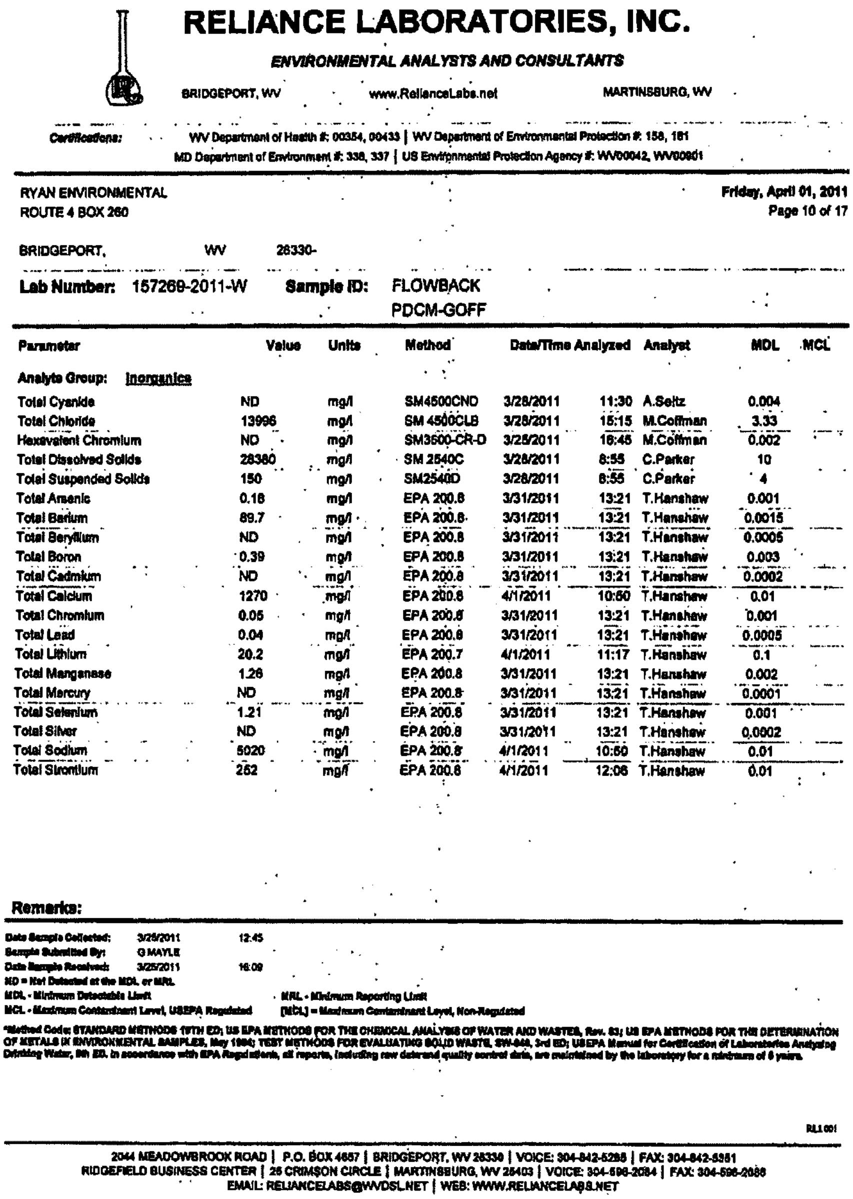

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Certifications: WV Department of Health #: 00354, 00433 | WV Department of Environmental Protection #: 158, 181
MD Department of Environment #: 336, 337 | US Environmental Protection Agency #: WV00042, WV00901

RYAN ENVIRONMENTAL
ROUTE 4 BOX 260

BRIDGEPORT, WV 26330-

Friday, April 01, 2011
Page 10 of 17

Lab Number: 157269-2011-W **Sample ID:** FLOWBACK
PDCM-GOFF

Parameter	Value	Units	Method	Date/Time Analyzed		Analyst	MDL	MCL
Analyte Group: Inorganics								
Total Cyanide	ND	mg/l	SM4500CND	3/28/2011	11:30	A.Seitz	0.004	
Total Chloride	13996	mg/l	SM 4500CLB	3/28/2011	15:15	M.Coffman	3.33	
Hexavalent Chromium	ND	mg/l	SM3500-CR-D	3/25/2011	16:45	M.Coffman	0.002	
Total Dissolved Solids	28380	mg/l	SM 2540C	3/28/2011	8:55	C.Parker	10	
Total Suspended Solids	150	mg/l	SM2540D	3/28/2011	8:55	C.Parker	4	
Total Arsenic	0.18	mg/l	EPA 200.8	3/31/2011	13:21	T.Hanshaw	0.001	
Total Barium	89.7	mg/l	EPA 200.8	3/31/2011	13:21	T.Hanshaw	0.0015	
Total Beryllium	ND	mg/l	EPA 200.8	3/31/2011	13:21	T.Hanshaw	0.0005	
Total Boron	0.39	mg/l	EPA 200.8	3/31/2011	13:21	T.Hanshaw	0.003	
Total Cadmium	ND	mg/l	EPA 200.8	3/31/2011	13:21	T.Hanshaw	0.0002	
Total Calcium	1270	mg/l	EPA 200.8	4/1/2011	10:50	T.Hanshaw	0.01	
Total Chromium	0.05	mg/l	EPA 200.8	3/31/2011	13:21	T.Hanshaw	0.001	
Total Lead	0.04	mg/l	EPA 200.8	3/31/2011	13:21	T.Hanshaw	0.0005	
Total Lithium	20.2	mg/l	EPA 200.7	4/1/2011	11:17	T.Hanshaw	0.1	
Total Manganese	1.26	mg/l	EPA 200.8	3/31/2011	13:21	T.Hanshaw	0.002	
Total Mercury	ND	mg/l	EPA 200.8	3/31/2011	13:21	T.Hanshaw	0.0001	
Total Selenium	1.21	mg/l	EPA 200.8	3/31/2011	13:21	T.Hanshaw	0.001	
Total Silver	ND	mg/l	EPA 200.8	3/31/2011	13:21	T.Hanshaw	0.0002	
Total Sodium	5020	mg/l	EPA 200.8	4/1/2011	10:50	T.Hanshaw	0.01	
Total Strontium	262	mg/l	EPA 200.8	4/1/2011	12:06	T.Hanshaw	0.01	

Remarks:

Date Sample Collected:	3/25/2011	12:45
Sample Submitted By:	G MAYLE	
Date Sample Received:	3/25/2011	16:09

ND = Not Detected at the MDL or MRL
MDL - Minimum Detectable Limit
MRL - Minimum Reporting Limit
MCL - Maximum Contaminant Level, USEPA Regulated
[MCL] = Maximum Contaminant Level, Non-Regulated

*Method Code: STANDARD METHODS 19TH ED; US EPA METHODS FOR THE CHEMICAL ANALYSIS OF WATER AND WASTES, Rev. 83; US EPA METHODS FOR THE DETERMINATION OF METALS IN ENVIRONMENTAL SAMPLES, May 1994; TEST METHODS FOR EVALUATING SOLID WASTE, SW-846, 3rd ED; USEPA Manual for Certification of Laboratories Analyzing Drinking Water, 5th ED. In accordance with EPA Regulations, all reports, including raw data and quality control data, are maintained by the laboratory for a minimum of 5 years.

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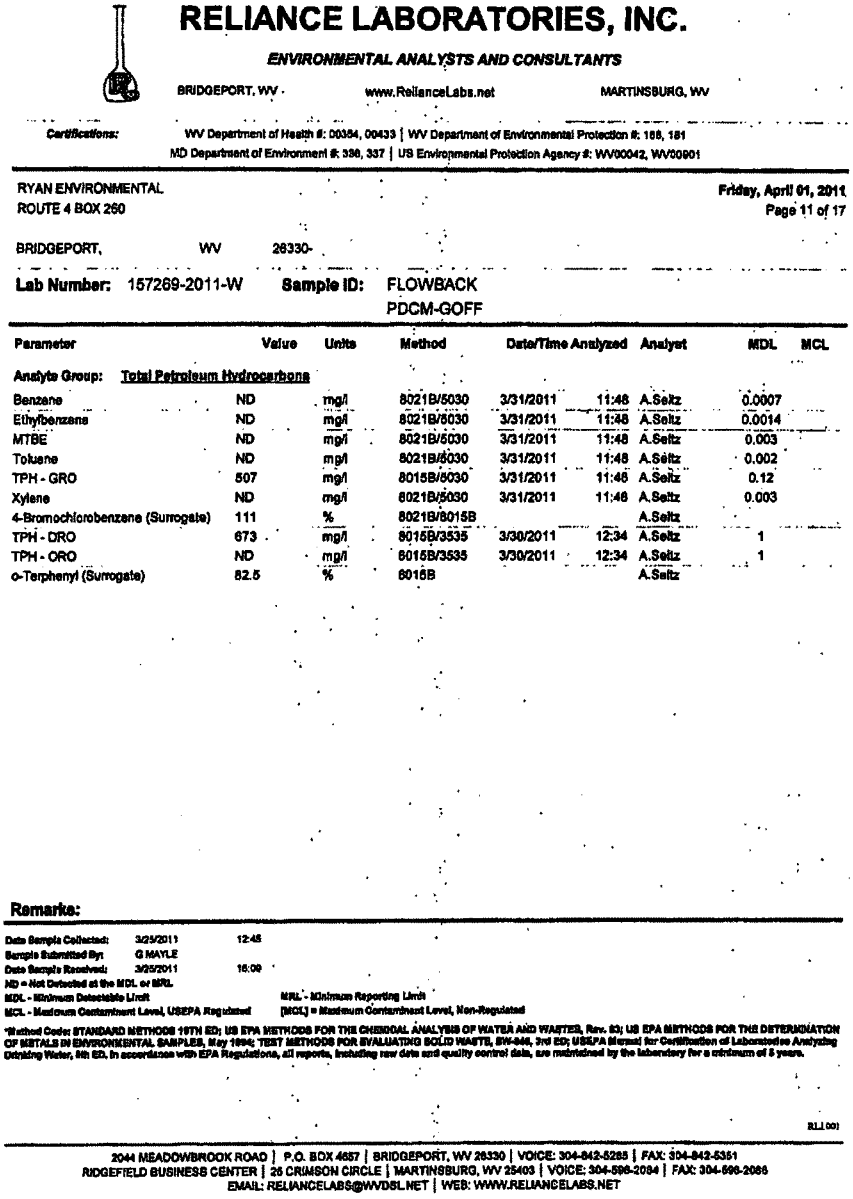

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MD Department of Environment #: 336, 337 | US Environmental Protection Agency #: WV00042, WV00901

RYAN ENVIRONMENTAL
ROUTE 4 BOX 260

BRIDGEPORT, WV 26330-

Friday, April 01, 2011
Page 11 of 17

Lab Number: 157269-2011-W **Sample ID:** FLOWBACK
PDCM-GOFF

Parameter	Value	Units	Method	Date/Time Analyzed		Analyst	MDL	MCL
Analyte Group: Total Petroleum Hydrocarbons								
Benzene	ND	mg/l	8021B/5030	3/31/2011	11:48	A.Seitz	0.0007	
Ethylbenzene	ND	mg/l	8021B/5030	3/31/2011	11:48	A.Seitz	0.0014	
MTBE	ND	mg/l	8021B/5030	3/31/2011	11:48	A.Seitz	0.003	
Toluene	ND	mg/l	8021B/5030	3/31/2011	11:48	A.Seitz	0.002	
TPH - GRO	507	mg/l	8015B/5030	3/31/2011	11:48	A.Seitz	0.12	
Xylene	ND	mg/l	8021B/5030	3/31/2011	11:48	A.Seitz	0.003	
4-Bromochlorobenzene (Surrogate)	111	%	8021B/8015B			A.Seitz		
TPH - DRO	673	mg/l	8015B/3535	3/30/2011	12:34	A.Seitz	1	
TPH - ORO	ND	mg/l	8015B/3535	3/30/2011	12:34	A.Seitz	1	
o-Terphenyl (Surrogate)	82.5	%	8015B			A.Seitz		

Remarks:

Date Sample Collected: 3/25/2011 12:45
Sample Submitted By: G MAYLE
Date Sample Received: 3/25/2011 16:00
ND = Not Detected at the MDL or MRL
MDL - Minimum Detectable Limit
MRL - Minimum Reporting Limit
MCL - Maximum Contaminant Level, USEPA Regulated
[MCL] = Maximum Contaminant Level, Non-Regulated

*Method Code: STANDARD METHODS 19TH ED; US EPA METHODS FOR THE CHEMICAL ANALYSIS OF WATER AND WASTES, Rev. 83; US EPA METHODS FOR THE DETERMINATION OF METALS IN ENVIRONMENTAL SAMPLES, May 1994; TEST METHODS FOR EVALUATING SOLID WASTE, SW-846, 3rd ED; USEPA Manual for Certification of Laboratories Analyzing Drinking Water, 5th ED. In accordance with EPA Regulations, all reports, including raw data and quality control data, are maintained by the laboratory for a minimum of 5 years.

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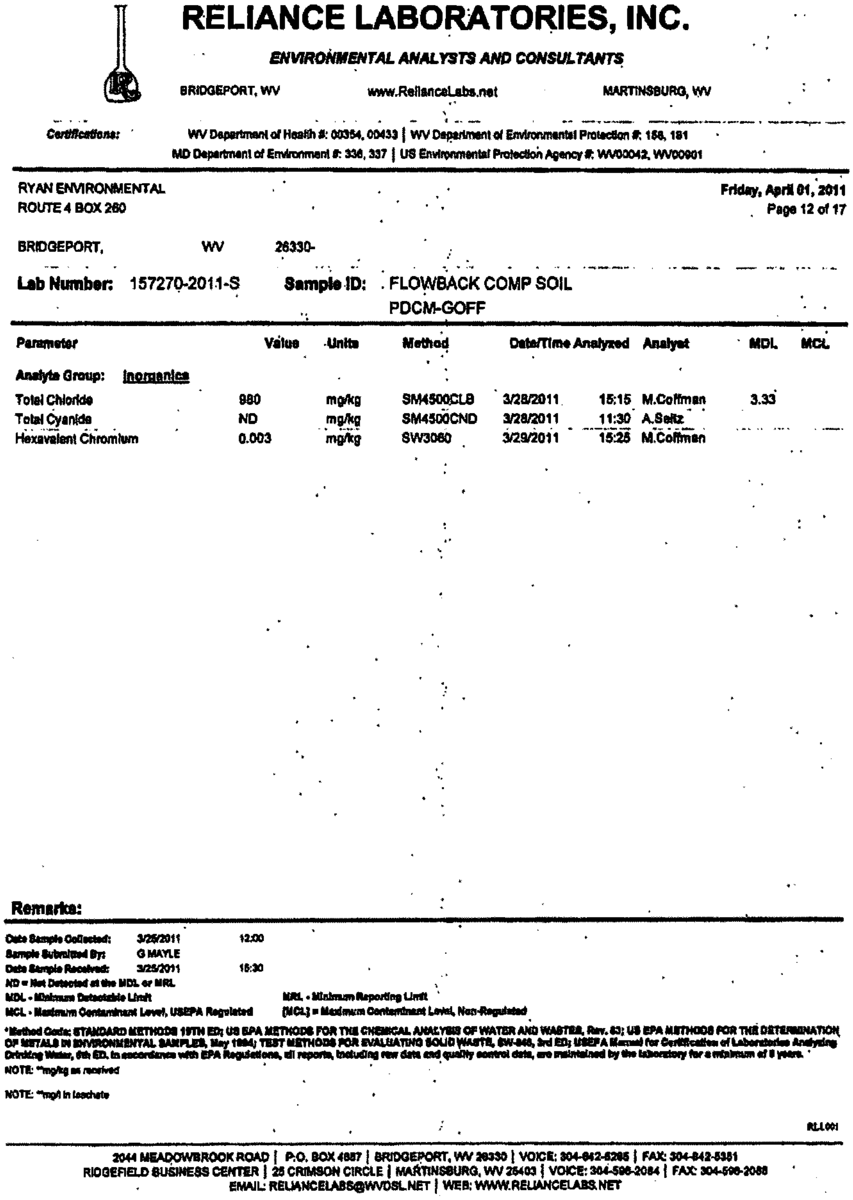

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RYAN ENVIRONMENTAL
ROUTE 4 BOX 260

BRIDGEPORT, WV 26330-

Friday, April 01, 2011
Page 12 of 17

Lab Number: 157270-2011-S **Sample ID:** FLOWBACK COMP SOIL
PDCM-GOFF

Parameter	**Value**	**Units**	**Method**	**Date/Time Analyzed**	**Analyst**	**MDL**	**MCL**
Analyte Group: Inorganics							
Total Chloride	980	mg/kg	SM4500CLB	3/28/2011 15:15	M.Coffman	3.33	
Total Cyanide	ND	mg/kg	SM4500CND	3/28/2011 11:30	A.Seitz		
Hexavalent Chromium	0.003	mg/kg	SW3060	3/29/2011 15:25	M.Coffman		

Remarks:

Date Sample Collected:	3/25/2011	12:00
Sample Submitted By:	G MAYLE	
Date Sample Received:	3/25/2011	15:30

ND = Not Detected at the MDL or MRL
MDL - Minimum Detectable Limit **MRL - Minimum Reporting Limit**
MCL - Maximum Contaminant Level, USEPA Regulated **(MCL) = Maximum Contaminant Level, Non-Regulated**

***Method Code: STANDARD METHODS 19TH ED; US EPA METHODS FOR THE CHEMICAL ANALYSIS OF WATER AND WASTES, Rev. 83; US EPA METHODS FOR THE DETERMINATION OF METALS IN ENVIRONMENTAL SAMPLES, May 1994; TEST METHODS FOR EVALUATING SOLID WASTE, SW-846, 3rd ED; USEPA Manual for Certification of Laboratories Analyzing Drinking Water, 5th ED. In accordance with EPA Regulations, all reports, including raw data and quality control data, are maintained by the laboratory for a minimum of 5 years.**

NOTE: **mg/kg as received

NOTE: **mg/l in leachate

RLL001

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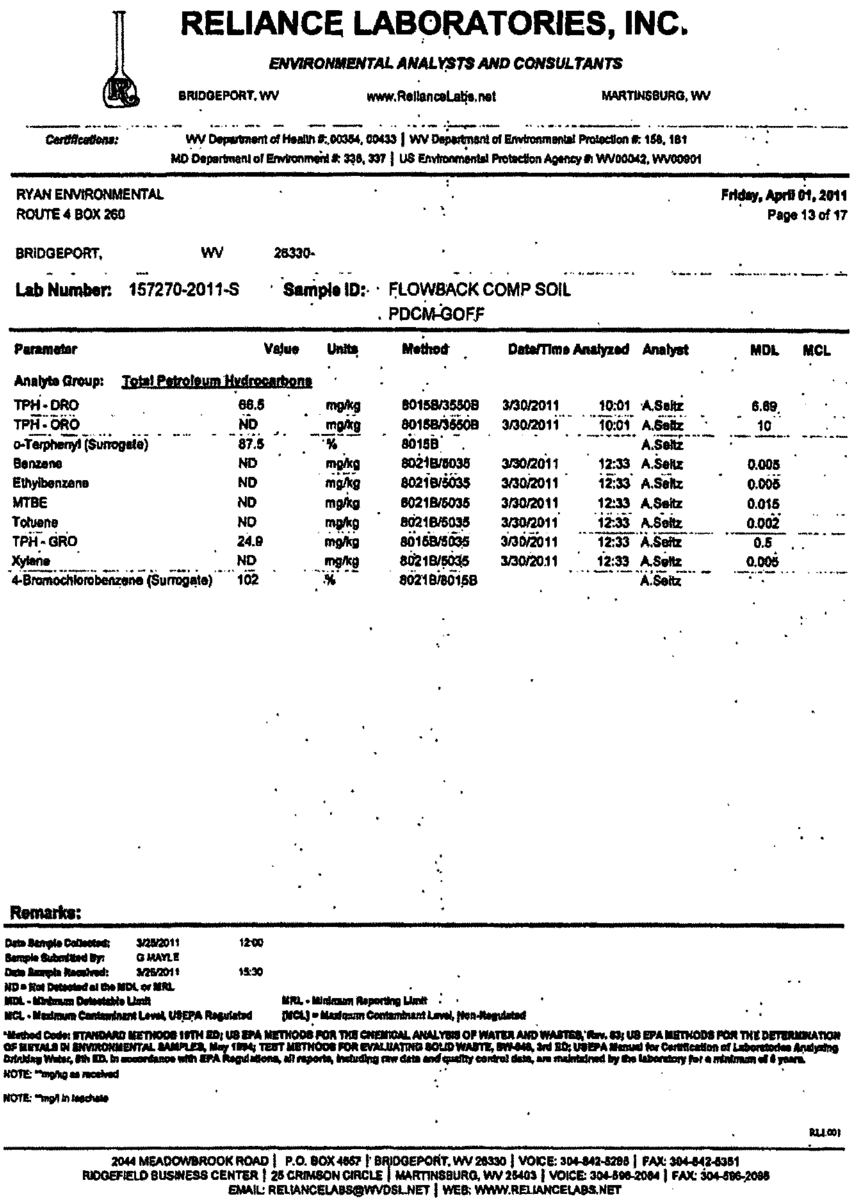

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RYAN ENVIRONMENTAL
ROUTE 4 BOX 260

BRIDGEPORT, WV 26330-

Friday, April 01, 2011
Page 13 of 17

Lab Number: 157270-2011-S **Sample ID:** FLOWBACK COMP SOIL
PDCM-GOFF

Parameter	**Value**	**Units**	**Method**	**Date/Time Analyzed**		**Analyst**	**MDL**	**MCL**
Analyte Group: **Total Petroleum Hydrocarbons**								
TPH - DRO	66.5	mg/kg	8015B/3550B	3/30/2011	10:01	A.Seitz	6.69	
TPH - ORO	ND	mg/kg	8015B/3550B	3/30/2011	10:01	A.Seitz	10	
o-Terphenyl (Surrogate)	87.5	%	8015B			A.Seitz		
Benzene	ND	mg/kg	8021B/5035	3/30/2011	12:33	A.Seitz	0.005	
Ethylbenzene	ND	mg/kg	8021B/5035	3/30/2011	12:33	A.Seitz	0.005	
MTBE	ND	mg/kg	8021B/5035	3/30/2011	12:33	A.Seitz	0.015	
Toluene	ND	mg/kg	8021B/5035	3/30/2011	12:33	A.Seitz	0.002	
TPH - GRO	24.9	mg/kg	8015B/5035	3/30/2011	12:33	A.Seitz	0.5	
Xylene	ND	mg/kg	8021B/5035	3/30/2011	12:33	A.Seitz	0.005	
4-Bromochlorobenzene (Surrogate)	102	%	8021B/8015B			A.Seitz		

Remarks:

Date Sample Collected:	3/25/2011	12:00
Sample Submitted By:	G MAYLE	
Date Sample Received:	3/25/2011	15:30

ND = Not Detected at the MDL or MRL
MDL - Minimum Detectable Limit
MRL - Minimum Reporting Limit
MCL - Maximum Contaminant Level, USEPA Regulated
(MCL) = Maximum Contaminant Level, Non-Regulated

*Method Code: STANDARD METHODS 19TH ED; US EPA METHODS FOR THE CHEMICAL ANALYSIS OF WATER AND WASTES, Rev. 83; US EPA METHODS FOR THE DETERMINATION OF METALS IN ENVIRONMENTAL SAMPLES, May 1994; TEST METHODS FOR EVALUATING SOLID WASTE, SW-846, 3rd ED; USEPA Manual for Certification of Laboratories Analyzing Drinking Water, 5th ED. In accordance with EPA Regulations, all reports, including raw data and quality control data, are maintained by the laboratory for a minimum of 5 years.

NOTE: **mg/kg as received

NOTE: **mg/l in leachate

RLI.001

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RYAN ENVIRONMENTAL
ROUTE 4 BOX 260

BRIDGEPORT, WV 26330-

Friday, April 01, 2011
Page 14 of 17

Lab Number: 157270-2011-S **Sample ID:** FLOWBACK COMP SOIL
PDCM-GOFF

Parameter	Value	Units	Method	Date/Time Analyzed		Analyst	MDL	MCL
Analyte Group: TCLP								
Particle Size	-0.375	inches	EPA 1311	3/28/2011	10:45	T.Hanshaw		
TCLP			EPA 1311	3/28/2011	10:45	T.Hanshaw		
TCLP Solids	76.4	%	EPA 1311	3/31/2011	14:30	T.Hanshaw		
Total Arsenic	ND	mg/kg	EPA 6010C	3/31/2011	13:01	T.Hanshaw		
Total Barium	1.24	mg/kg	EPA 6010C	3/31/2011	10:30	T.Hanshaw		
Total Beryllium	ND	mg/kg	EPA 6010C	3/31/2011	14:05	T.Hanshaw		
Total Boron	0.09	mg/kg	EPA 6010C	3/31/2011	14:05	T.Hanshaw		
Total Cadmium	0.03	mg/kg	EPA 6010C	3/31/2011	10:30	T.Hanshaw		
Total Calcium	704	mg/kg	EPA 6010C	12/30/1899	10:02	T.Hanshaw		
Total Chromium	0.03	mg/kg	EPA 6010C	3/31/2011	10:30	T.Hanshaw		
Total Lead	0.05	mg/kg	EPA 6010C	3/31/2011	10:30	T.Hanshaw		
Total Lithium	0.06	mg/kg	EPA 6010C	4/1/2011	11:19	T.Hanshaw		
Total Manganese	1.62	mg/kg	EPA 6010C	3/31/2011	10:30	T.Hanshaw		
Total Mercury	ND	mg/kg	EPA 7471A	3/31/2011	14:55	M.Coffman		
Total Selenium	ND	mg/kg	EPA 6010C	3/31/2011	14:48	T.Hanshaw		
Total Silver	ND	mg/kg	EPA 6010C	3/31/2011	15:35	T.Hanshaw		
Total Sodium	944	mg/kg	EPA 6010C	4/1/2011	10:02	T.Hanshaw		

Remarks:

Date Sample Collected:	3/28/2011	12:00
Sample Submitted By:	G MAYLE	
Date Sample Received:	3/25/2011	15:30

ND = Not Detected at the MDL or MRL
MDL - Minimum Detectable Limit MRL - Minimum Reporting Limit
MCL - Maximum Contaminant Level, USEPA Regulated [MCL] = Maximum Contaminant Level, Non-Regulated

*Method Code: STANDARD METHODS 18TH ED; US EPA METHODS FOR THE CHEMICAL ANALYSIS OF WATER AND WASTES, Rev. 83; US EPA METHODS FOR THE DETERMINATION OF METALS IN ENVIRONMENTAL SAMPLES, May 1994; TEST METHODS FOR EVALUATING SOLID WASTE, SW-846, 3rd ED; USEPA Manual for Certification of Laboratories Analyzing Drinking Water, 5th ED. In accordance with EPA Regulations, all reports, including raw data and quality control data, are maintained by the laboratory for a minimum of 5 years.

NOTE: **mg/kg as received

NOTE: **mg/l in leachate

RLJ.001

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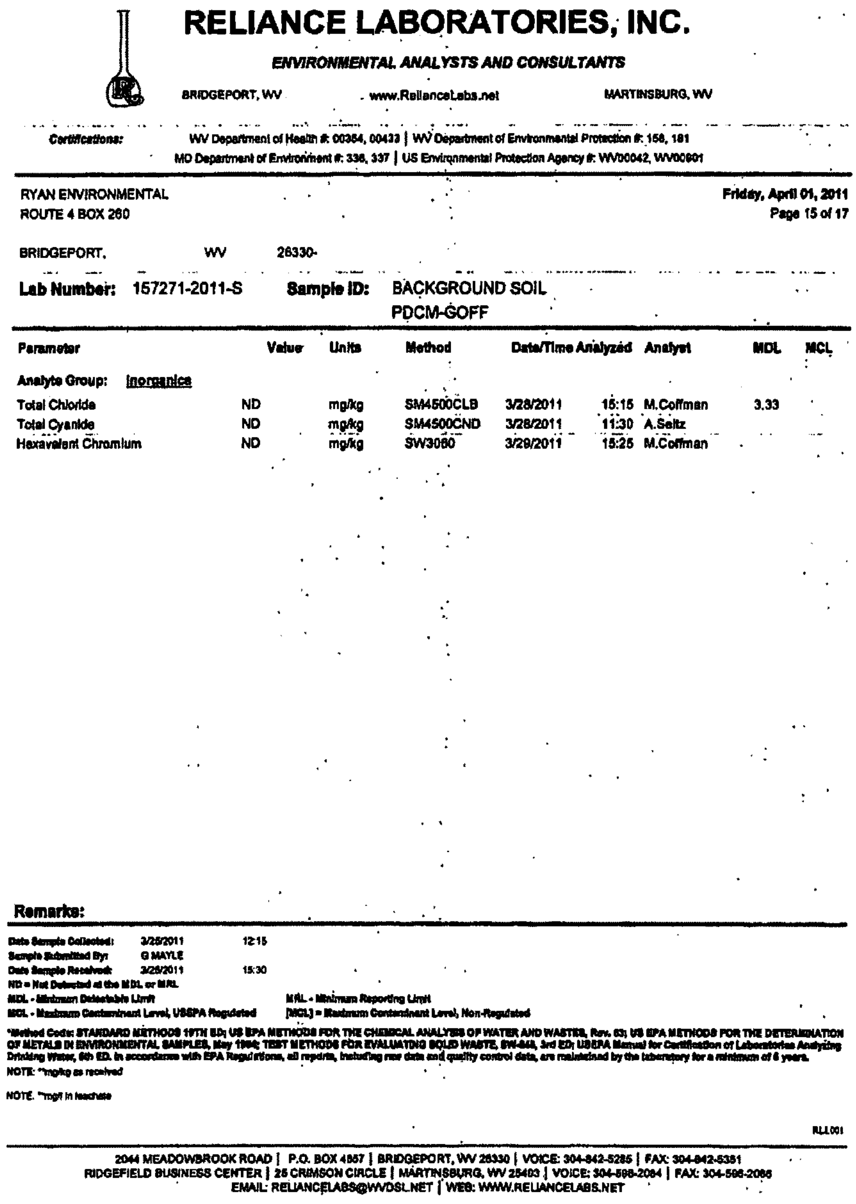

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RYAN ENVIRONMENTAL
ROUTE 4 BOX 260

BRIDGEPORT, WV 26330-

Friday, April 01, 2011
Page 15 of 17

Lab Number: 157271-2011-S **Sample ID:** BACKGROUND SOIL PDCM-GOFF

Analyte Group: Inorganics

Parameter	Value	Units	Method	Date/Time Analyzed		Analyst	MDL	MCL
Total Chloride	ND	mg/kg	SM4500CLB	3/28/2011	15:15	M.Coffman	3.33	
Total Cyanide	ND	mg/kg	SM4500CND	3/28/2011	11:30	A.Seitz		
Hexavalent Chromium	ND	mg/kg	SW3060	3/29/2011	15:25	M.Coffman		

Remarks:

Date Sample Collected:	3/25/2011	12:15
Sample Submitted By:	G MAYLE	
Date Sample Received:	3/25/2011	15:30

ND = Not Detected at the MDL or MRL
MDL - Minimum Detectable Limit MRL - Minimum Reporting Limit
MCL - Maximum Contaminant Level, USEPA Regulated [MCL] = Maximum Contaminant Level, Non-Regulated

*Method Code: STANDARD METHODS 19TH ED; US EPA METHODS FOR THE CHEMICAL ANALYSES OF WATER AND WASTES, Rev. 83; US EPA METHODS FOR THE DETERMINATION OF METALS IN ENVIRONMENTAL SAMPLES, May 1994; TEST METHODS FOR EVALUATING SOLID WASTE, SW-846, 3rd ED; USEPA Manual for Certification of Laboratories Analyzing Drinking Water, 5th ED. In accordance with EPA Regulations, all reports, including raw data and quality control data, are maintained by the laboratory for a minimum of 5 years.

NOTE: **mg/kg as received

NOTE: **mg/l in leachate

RLL001

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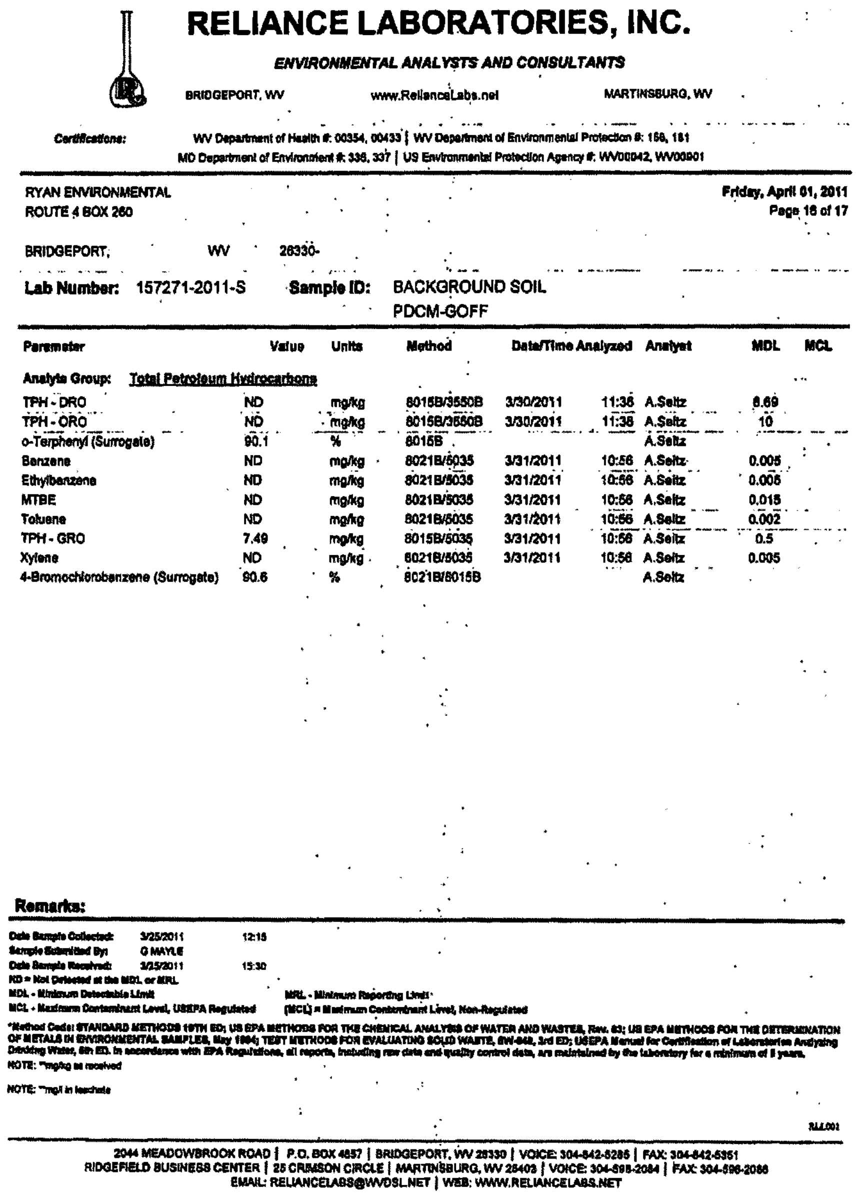

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RYAN ENVIRONMENTAL
ROUTE 4 BOX 260

BRIDGEPORT, WV 26330-

Friday, April 01, 2011
Page 16 of 17

Lab Number: 157271-2011-S **Sample ID:** BACKGROUND SOIL
PDCM-GOFF

Parameter	**Value**	**Units**	**Method**	**Date/Time Analyzed**	**Analyst**	**MDL**	**MCL**
Analyte Group: Total Petroleum Hydrocarbons							
TPH - DRO	ND	mg/kg	8015B/3550B	3/30/2011 11:38	A.Seitz	6.69	
TPH - ORO	ND	mg/kg	8015B/3550B	3/30/2011 11:38	A.Seitz	10	
o-Terphenyl (Surrogate)	90.1	%	8015B		A.Seitz		
Benzene	ND	mg/kg	8021B/5035	3/31/2011 10:56	A.Seitz	0.005	
Ethylbenzene	ND	mg/kg	8021B/5035	3/31/2011 10:56	A.Seitz	0.005	
MTBE	ND	mg/kg	8021B/5035	3/31/2011 10:56	A.Seitz	0.015	
Toluene	ND	mg/kg	8021B/5035	3/31/2011 10:56	A.Seitz	0.002	
TPH - GRO	7.49	mg/kg	8015B/5035	3/31/2011 10:56	A.Seitz	0.5	
Xylene	ND	mg/kg	8021B/5035	3/31/2011 10:56	A.Seitz	0.005	
4-Bromochlorobenzene (Surrogate)	90.6	%	8021B/8015B		A.Seitz		

Remarks:

Date Sample Collected:	3/25/2011	12:15
Sample Submitted By:	G MAYLE	
Date Sample Received:	3/25/2011	15:30

ND = Not Detected at the MDL or MRL
MDL - Minimum Detectable Limit MRL - Minimum Reporting Limit
MCL - Maximum Contaminant Level, USEPA Regulated (MCL) = Maximum Contaminant Level, Non-Regulated

*Method Code: STANDARD METHODS 19TH ED; US EPA METHODS FOR THE CHEMICAL ANALYSIS OF WATER AND WASTES, Rev. 83; US EPA METHODS FOR THE DETERMINATION OF METALS IN ENVIRONMENTAL SAMPLES, May 1994; TEST METHODS FOR EVALUATING SOLID WASTE, SW-846, 3rd ED; USEPA Manual for Certification of Laboratories Analyzing Drinking Water, 5th ED. In accordance with EPA Regulations, all reports, including raw data and quality control data, are maintained by the laboratory for a minimum of 5 years.

NOTE: **mg/kg as received

NOTE: **mg/l in leachate

RLL001

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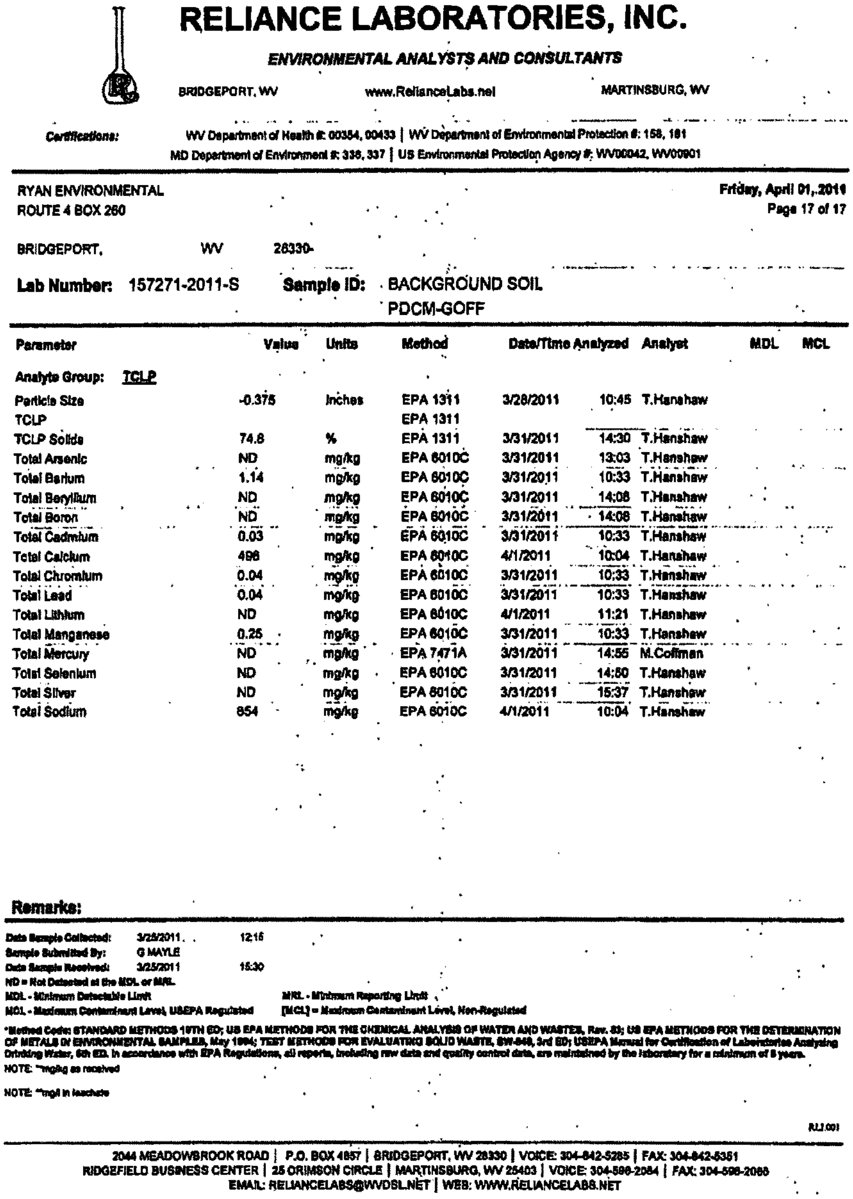

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RYAN ENVIRONMENTAL
ROUTE 4 BOX 260

BRIDGEPORT, WV 26330-

Friday, April 01, 2011
Page 17 of 17

Lab Number: 157271-2011-S **Sample ID:** BACKGROUND SOIL
PDCM-GOFF

Parameter	**Value**	**Units**	**Method**	**Date/Time Analyzed**	**Analyst**	**MDL**	**MCL**
Analyte Group: TCLP							
Particle Size	-0.375	Inches	EPA 1311	3/28/2011 10:45	T.Hanshaw		
TCLP			EPA 1311				
TCLP Solids	74.8	%	EPA 1311	3/31/2011 14:30	T.Hanshaw		
Total Arsenic	ND	mg/kg	EPA 6010C	3/31/2011 13:03	T.Hanshaw		
Total Barium	1.14	mg/kg	EPA 6010C	3/31/2011 10:33	T.Hanshaw		
Total Beryllium	ND	mg/kg	EPA 6010C	3/31/2011 14:08	T.Hanshaw		
Total Boron	ND	mg/kg	EPA 6010C	3/31/2011 14:08	T.Hanshaw		
Total Cadmium	0.03	mg/kg	EPA 6010C	3/31/2011 10:33	T.Hanshaw		
Total Calcium	496	mg/kg	EPA 6010C	4/1/2011 10:04	T.Hanshaw		
Total Chromium	0.04	mg/kg	EPA 6010C	3/31/2011 10:33	T.Hanshaw		
Total Lead	0.04	mg/kg	EPA 6010C	3/31/2011 10:33	T.Hanshaw		
Total Lithium	ND	mg/kg	EPA 6010C	4/1/2011 11:21	T.Hanshaw		
Total Manganese	0.25	mg/kg	EPA 6010C	3/31/2011 10:33	T.Hanshaw		
Total Mercury	ND	mg/kg	EPA 7471A	3/31/2011 14:55	M.Coffman		
Total Selenium	ND	mg/kg	EPA 6010C	3/31/2011 14:50	T.Hanshaw		
Total Silver	ND	mg/kg	EPA 6010C	3/31/2011 15:37	T.Hanshaw		
Total Sodium	854	mg/kg	EPA 6010C	4/1/2011 10:04	T.Hanshaw		

Remarks:

Date Sample Collected:	3/25/2011	12:15
Sample Submitted By:	G MAYLE	
Date Sample Received:	3/25/2011	15:30

ND = Not Detected at the MDL or MRL.
MDL - Minimum Detectable Limit **MRL - Minimum Reporting Limit**
MCL - Maximum Contaminant Level, USEPA Regulated **[MCL] = Maximum Contaminant Level, Non-Regulated**

***Method Code: STANDARD METHODS 19TH ED; US EPA METHODS FOR THE CHEMICAL ANALYSIS OF WATER AND WASTES, Rev. 83; US EPA METHODS FOR THE DETERMINATION OF METALS IN ENVIRONMENTAL SAMPLES, May 1994; TEST METHODS FOR EVALUATING SOLID WASTE, SW-846, 3rd ED; USEPA Manual for Certification of Laboratories Analyzing Drinking Water, 5th ED. In accordance with EPA Regulations, all reports, including raw data and quality control data, are maintained by the laboratory for a minimum of 5 years.**

NOTE: **mg/kg as received

NOTE: **mg/l in leachate

RLI.001

2044 MEADOWBROOK ROAD | P.O. BOX 4657 | BRIDGEPORT, WV 26330 | VOICE: 304-842-5285 | FAX: 304-842-5351
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IOGCC 75 Anniversary

INTERSTATE
Oil & Gas
COMPACT COMMISSION

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Oklahoma
Pennsylvania
South Dakota
Texas
Utah
Virginia
West Virginia
Wyoming

April 8, 2011

The Honorable James M. Inhofe
United States Senate
205 Russell Senate Office Building
Washington, DC 20510 -3603

Dear Senator Inhofe:

Thank you for the opportunity to provide information on the states' role in regulating the practice of hydraulic fracturing in the completion of oil and natural gas wells onshore the United States. As you are aware, the Interstate Oil and Gas Compact Commission represents the governors of 38 oil and gas producing states, and the organization and its members have been regulating fracturing since its early beginnings six decades ago.

Over the years, states have created a comprehensive body of regulations that cover the entire spectrum of hydraulic fracturing – from cradle to grave, if you will. Thousands of incidents have been investigated regarding the drilling and completion of wells, but there has never been a documented case of drinking water contamination linked specifically to the science-based process of hydraulic fracturing.

I can speak for the states in saying that we would welcome the opportunity to become more closely involved in the study of this topic being contacted by the U.S. Environmental Protection Agency, and now, I understand, by an advisory committee to the U.S. Department of Energy.

As always, if you need additional, more specific information on how states regulate the practice of hydraulic fracturing, we would welcome the chance to respond. Thank you for the opportunity to present our views before the Committee.

Sincerely,

Gerry Baker
Associate Executive Director
(405) 525-3556, extension 112, or
(405) 664-7362

GB/mo

Attachment: Background documentation re hydraulic fracturing

IOGCC 75 Anniversary

INTERSTATE
Oil & Gas
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West Virginia
Wyoming

March 26, 2010

Mr. Edward Hanlon
Designated Federal Officer
EPA Science Advisory Board (1400F)
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, NW
Washington, DC 20460

Dear Mr. Hanlon:

I am writing on behalf of the nation's 38 oil and natural gas producing states represented by the Interstate Oil and Gas Compact Commission (IOGCC). As one of the most prominent stakeholders in the study proposed by the U.S. Environmental Protection Agency (EPA) on hydraulic fracturing, the IOGCC is most interested in fully participating and cooperating in this work product.

Protection of potential drinking water sources is a critical, uncompromised function of oil and gas regulatory officials at the state level. It is a fundamental job responsibility that is never taken for granted. For this reason alone, the IOGCC will cooperate to the greatest degree possible in this research effort.

The IOGCC member states have demonstrated this cooperative spirit by their eight-year commitment to participating in an IOGCC/EPA Task Force that is designed to keep state and federal co-regulators informed on issues of common concern. During this time, many issues have been explored by the Task Force, including hydraulic fracturing. In fact, the IOGCC has arranged for presentations directly to Task Force members in an attempt to educate members about state programs designed to protect the environment during hydraulic fracturing operations.

No government organization has more expertise, data and experience than the collective offices of state oil and gas regulatory bodies. States have regulated more than 1 million fracturing operations in the last 60 years. While there has yet to be a documented case of drinking water contamination as a result of hydraulic fracturing, the IOGCC strongly believes its members should be closely involved in every discussion of the study's scope and design.

Specifically, it is noted that the study as proposed envisions an undefined level of "field work." Since field work would most likely involve functions currently regulated by states, the IOGCC recommends that state inspectors be notified of and allowed to participate in both the planning and conduct of any activities.

In addition, the IOGCC encourages the Environmental Engineering Committee and the Science Advisory Board to suggest that research plans regarding any regulatory matter be presented to state regulatory officials and particularly oil and gas regulatory offices. As the principal repositories of information on hydraulic fracturing, states should be the point of first contact for any research activity. The IOGCC would provide appropriate contact information for state oil and gas regulatory offices if necessary.

Due to the short review time and the use of some vague terms within the scoping document, it is difficult to evaluate its full intent. The IOGCC encourages the Environmental Engineering Committee to suggest further dialog with the states to ensure it satisfies the intent of the language of the U.S. House Appropriations Conference Committee "…to carry out a study on the relationship between hydraulic fracturing and drinking water…" in consultation with interstate regulatory agencies while not duplicating efforts undertaken by EPA in 2004 that found no cases of drinking water contamination caused by hydraulic fracturing in coalbed methane recovery operations.

The additional information that follows documents the states' long-time involvement in the process of regulating hydraulic fracturing and their unwavering commitment to environmental protection. IOGCC staff members are available to provide additional detail and participation in the study-design process as requested.

Sincerely,

D. Gerow Baker
Associate Executive Director

Attachments: 2003 Survey of States Re: Hydraulic Fracturing
Testimony Submitted to The House Committee on Energy and Commerce, Subcommittee On Energy And Mineral Resources, June 2009, Lynn Helms, Director of The Department of Mineral Resources of The Industrial Commission of The State of North Dakota
Testimony Submitted to The House Committee on Oversight and Government Reform, October 2007, David E. Bolin, Deputy Director of the State Oil and
Testimony Submitted to The House Committee on Resources, July 2005, Victor Carrillo, Chairman, Texas Railroad Commission
Guest Opinion, Tom Richmond, Division Administrator, Montana Board of Oil and Gas Conservation, Department of Natural Resources
White Paper: Safeguards Utilized by State Oil and Gas Conservation Agencies for Protecting From Potential Adverse Effects on Water From Hydraulic Fracturing, 2009, Marvin Rogers, Of Counsel, Alabama State Oil and Gas Board
Letter to President Barack Obama, February 2009, from IOGCC Executive Director with IOGCC Resolution 09.011 on Hydraulic Fracturing
State Resolutions on Hydraulic Fracturing: Alabama, Louisiana, North Dakota, Oklahoma, Utah and Wyoming

2003 SURVEY OF STATES RE: HYDRAULIC FRACTURING

STATE	YR STATE BEGAN REG.	FRACTURING DONE IN STATE?	HOW LONG FRACTURING ?	TYPE OF WELLS	APP. WELLS FRACKED ANNUALLY	APP. WELLS FRACTURED IN STATE TOTAL	% OF WELLS FRACKED	HARM ?
ALABAMA	1945	**YES**	1945	G,O,CSNG	285	5300	85%	**NO**
ALASKA	1958	**YES**	1981	G,O	55	1400	40%	**NO**
ARKANSAS	1939	**YES**	1980s	G,CSNG	150	N/A	75%	**NO**
CALIFORNIA	1915	**YES**	1970s	O,G	500	15,000	15%	**NO**
COLORADO	1951	**YES**	1980s	G,O,CSNG	1500	20,000	99%	**NO**
ILLINOIS	1939	**YES**	1950s	O	1,000	30 to 50,000	30%	**NO**
INDIANA	1947	**YES**	1950s	O,G	1,000	20,562	95%	**NO**
KANSAS	1933	**YES**	1960s	O,G,CSNG	900	50,000	40%	**NO**
KENTUCKY	1960	**YES**	1960s	G	1,000	30,000	50%	**NO**
LOUISIANA	1920s	**YES**	1960s	O,G	258	36,000	30%	**NO**
MICHIGAN	1927	**YES**	1970s	O,G	400	9,000	90%	**NO**
MISSISSIPPI	1939	**YES**	1960s	G	70	2 to 3,000	35%	**NO**
MONTANA	1954	**YES**	1950s	O,G	10	4,000	66%	**NO**
NEBRASKA	1959	**YES**	1950s	O,G	200	3,500	80%	**NO**
NEVADA	1954	**YES**	1980s	O	10	50	5%	**NO**
NEW MEXICO	1935	**YES**	1950s	O,G,CSNG	1,000	30,000	90%	**NO**
NEW YORK	1879	**YES**	1962	O,G	100	8,000	85%	**NO**
NORTH DAKOTA	1945	**YES**	1950s	O,G	15	290	10%	**NO**
OHIO	1965	**YES**	1950s	O,G	550	67,000	81%	**NO**
OKLAHOMA	1915	**YES**	1950s	O,G	1,150	58,000	60%	**NO**
PENNSYLVANIA	Pre-1900	**YES**	1950s	O,G,CSNG	2,000	118,000	99.9%	**NO**
SOUTH DAKOTA	1943	**YES**	1960s	O,G	10	195	90%	**NO**
TENNESSEE	1969	**YES**	1969	O,G	N/A	N/A	N/A	**NO**
TEXAS	1919	**YES**	1950s	O,G	20,220	361,000	50%	**NO**
UTAH	1955	**YES**	1970s	G,O	480	7,000	80%	**NO**
VIRGINIA	1950	**YES**	1970s	G,CSNG	300	3,000	100%	**NO**
WEST VIRGINIA	1929	**YES**	1960s	O,G,CSNG	1,000	25,000	95%	**NO**
WYOMING	1951	**YES**	1950s	O,G	500	25 to 30,000	66%	**NO**
				TOTALS:	**34,663**	**948,597**	**56.3%**	

Types of wells: G=Natural Gas, O=Oil, CSNG=Natural gas from coal seams   N/A = Specific numbers not available

TESTIMONY SUBMITTED TO THE HOUSE COMMITTEE ON NATURAL RESOURCES

SUBCOMMITTEE ON ENERGY AND MINERAL RESOURCES

BY LYNN D. HELMS, DIRECTOR OF THE DEPARTMENT OF MINERAL RESOURCES OF THE INDUSTRIAL COMMISSION OF THE STATE OF NORTH DAKOTA

JUNE 4, 2009

Good morning Chairman Costa, Ranking Member Lamborn, and members of the Committee. My name is Lynn Helms. I am the Director of the Department of Mineral Resources of the Industrial Commission of the State of North Dakota. I am here today representing the Industrial Commission, the State of North Dakota, and other member states of the Interstate Oil and Gas Compact Commission (IOGCC) to express my views as a state regulator on development of shale gas in the United States and as to the outstanding job that states are doing in regulating the development of this most important national resource.

The 30 member states of the IOGCC are responsible for more than 99% of the oil and natural gas produced onshore in the United States. Formed by Governors in 1935, the IOGCC is a congressionally chartered interstate compact. The organization, the nation's leading advocate for conservation and wise development of domestic petroleum resources, includes 30 member and 8 associate states. The mission of the IOGCC is two-fold: to conserve our nation's oil and gas resources and to protect human health and the environment. Our current chairman is Governor Brad Henry of Oklahoma.

In my testimony today I propose to begin with some information on the Bakken shale formation in North Dakota and, how, thanks to recent technological advances, it is providing this country with an abundant and critical domestic energy resource. I will also provide testimony as to the competency and commitment of state oil and gas regulators to protect our states' drinking water resources in the development of the country's shale energy resources.

North Dakota's Bakken Resource

Let me begin by talking about the Bakken formation. I note that because of high crude oil prices in 2007 and 2008 and the discovery of new technology that has made it possible to economically produce the Bakken formation in North Dakota and Montana, the state of North Dakota has recently moved from the country's 9th ranked state in daily oil production to number 5.

The Bakken Formation is a large unconventional oil and gas resource that underlies most of western North Dakota, eastern Montana, southeast Saskatchewan, and southwest Manitoba. The U.S. Geological Survey (USGS) stated in an April 2008 report that it is the largest continuous resource they have assessed in the lower 48 states.

The upper and lower members of the Bakken formation are world class petroleum source rocks. Published estimates of Bakken oil generation potential range from 10 billion barrels (Dow 1974) to 300 billion barrels (Flannery and Krause 2006). The unpublished work of Price estimated the Bakken oil generation potential at up to 503 billion barrels. An extensive oil sampling program conducted by the North Dakota Geological Survey has shown that the Bakken is "truly dysfunctional" with no evidence that Bakken-generated oil has migrated away from the Bakken pool as previously thought. The geological models presented by Price (unpublished) and by Flannery and Kraus (2006) were based on input from North Dakota Geological Survey geologists, samples from the North Dakota Core and Sample Library, and the well files from the North Dakota Oil and Gas Division establish the most likely range of oil and gas in-place estimates of 300-500 billion barrels of oil and 300-500 trillion cubic feet of associated natural gas.

This incredible resource was identified by geologists within months of the first commercial oil production in North Dakota in a well drilled on a farm north of Tioga, ND in 1951. Yet, economic production was rare until the remarkable technologies of the 21st century were brought to bear, including deep, long horizontal wells with multiple hydraulic fracture treatments. I might note that research funded by the U.S. Department of Energy (DOE) Office of Fossil Energy has helped advance these shale technologies, and I encourage strong Congressional support of the program.

Significantly, even after applying the latest tools available, the Bakken Formation is expected to yield only **1.4%** of its original oil in place, which is still a remarkable **4-7 billion barrels of oil and 4-7 trillion cubic feet of natural gas.** The Bakken play in North Dakota is still in the learning curve. North Dakota wells are still undergoing adjustments and modifications to the drilling and completion practices used for this formation. It is apparent that technology and the price of oil will dictate what is potentially recoverable from this formation. The current Bakken shale recovery estimate equals all U.S. crude oil imports from the Persian Gulf since 2000 and a full year of residential natural gas consumption for our nation. The proven portion of the middle Bakken member occupies over 8.4 million acres in western North Dakota. The current North Dakota drilling rig fleet is capable of developing 300,000 to 650,000 acres per year meaning full development could require 13 to 26 years and over 13,000 new wells each hydraulically fractured from 2 to 20 times. This is lot of energy for our country and jobs for the American economy.

State Regulation of Oil and Natural Gas Development

I'd like to now address the issue of how development of this shale resource in North Dakota, and throughout the country, is regulated so as to also protect and preserve our country's precious water resources. It is useful to understand the critical role that states play in the regulation of oil and natural gas resources in the United States. A history of oil and natural gas in North Dakota can serve as an illustrative example.

North Dakota Oil and Gas Regulatory History

In response to shallow natural gas discoveries used for domestic lighting and heating the North Dakota Legislature passed an oil and gas conservation law that prohibited production of gas unless it was tied to a distribution system in 1911. The 1941 Legislature later passed the first meaningful regulatory bill under the urging of then State Geologist Wilson M. Laird. As a result, North Dakota had an oil-conservation law in place when oil was discovered in the State ten years later, but following that first commercial oil production in April 1951 North Dakota saw the need to be part of the organization chartered by congress to assist states with oil and gas regulation. North Dakota joined the Interstate Oil Compact Commission in 1953 and the North Dakota Legislature revised the Oil and Gas Conservation Law to conform to the IOCC Model Act that same year. A Chief Petroleum Engineer was hired who immediately updated the rules to reflect the new law. Most states that produce oil and gas share a similar history and are also members of the IOGCC.

Every North Dakota Governor since 1987, around the time when North Dakota became one of the top 10 U.S. states in daily oil production, has chaired the organization.

The highlight of IOGCC meetings since 1988 has been the Council of State Regulatory Officials. At meetings of this group, the top oil and gas regulatory official of every member state and every oil and gas producing Canadian province, or their designee, shares with the group the top issues in their state or province. Recommendations from other states that have or are working with similar issues are frequently solicited. This forum allows state regulators to respond to new issues very quickly, consistently, and collaboratively. For example, within weeks of a recent home explosion in Ohio state regulatory officials were discussing the investigation by the Ohio Department of Natural Resources and the primary cementing failure that caused it. Another example of the efficacy of such a program is the frequent updates on the LEAF lawsuit and group discussions of the issues surrounding hydraulic fracturing in the United States that ensued.

When I began this job almost eleven years ago the relationship between the North Dakota Oil and Gas Division and other state and federal agencies whose jurisdiction overlapped in many areas was very mixed. Realizing that relationships change as do agency directors we moved aggressively to develop Memoranda of Agreement with those agencies that provide structure for both the regulators and regulated community and provide for period review and change. A national example of this is a Memorandum between the IOGCC and the U.S. Environmental Protection Agency (EPA) which provides for a process under which states and EPA regularly meet as environmental co-regulators.

Regulation to Protect Water Resources

As the head regulator of oil and natural gas development in the State of North Dakota and an officer of the IOGCC representing all oil and natural gas producing state regulators, I can assure you that we have no higher priority than the protection of our states' water resources – let me repeat no higher priority. Much of our entire regulatory framework, from drilling to completion, production, and finally plugging and abandonment, is centered around measures to prevent any contamination of the water resource. As a component of the completion of a well, hydraulic fracturing operations are thus thoroughly regulated and supervised by the states.

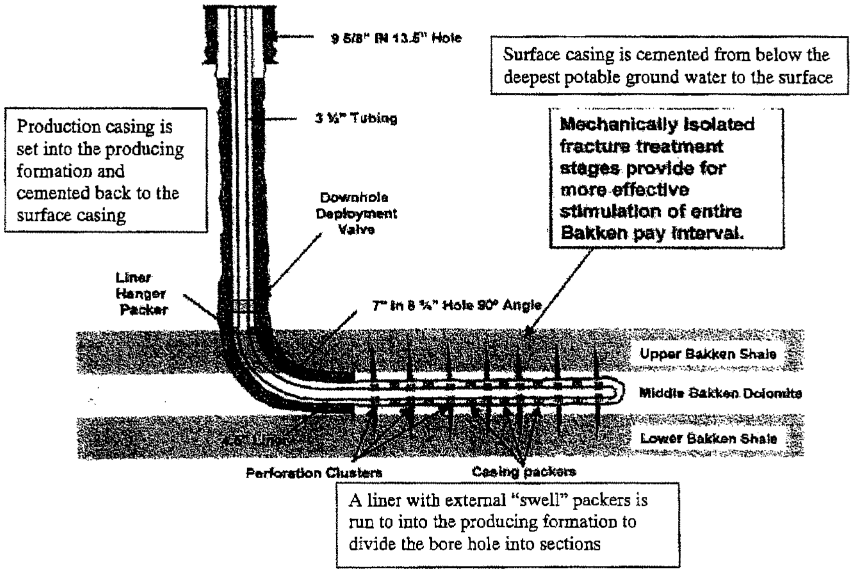
A major component of production operations is the proper storage and disposal of all production wastes, including hydraulic fracturing flow back water. These operations are carefully monitored, audited, and regulated in our state programs.

As I noted in my testimony above, hydraulic fracturing is a critical component of developing the Bakken formation, indeed every shale play throughout the U.S. and Canada. Without hydraulic fracturing, under regulation of the states, this resource could not be produced.

I have included both a picture of a hydraulic fracture treatment near Lake Sakakawea in North Dakota (page 5) and a diagram of a typical Bakken formation well (page 6) that shows how it is that water resources are protected during the oil and natural gas production operations, including hydraulic fracturing.

ND hydraulic fracture treatment:

ND Bakken shale well bore:



Surface casing is cemented from below the deepest potable ground water to the surface

Production casing is set into the producing formation and cemented back to the surface casing

Mechanically isolated fracture treatment stages provide for more effective stimulation of entire Bakken pay interval.

A liner with external "swell" packers is run to into the producing formation to divide the bore hole into sections

Hydraulic Fracturing Is Environmentally Safe

In a 1998 survey of state oil and gas regulatory agencies, conducted by the GWPC, twenty four state programs said they had not recorded any complaints of contamination to a USDW that the agency could attribute to hydraulic fracturing of coalbed methane zones.

In 2004 the Environmental Protection Agency published a final report summarizing a study to evaluate the potential threat to underground sources of drinking water from hydraulic fracturing of coal bed methane production wells and the Environmental Protection Agency concluded that "additional or further study is not warranted at this time..." and that "the injection of hydraulic fracturing fluids into coal bed methane wells poses minimal threat to the underground sources of drinking water".

Subsequently, the IOGCC conducted a survey of North Dakota and other oil and gas-producing states that found that there were no known cases of ground water contamination associated with hydraulic fracturing. Hydraulic fracturing is a common operation used in exploration and production by the oil and gas industry in North Dakota and all the member states of the IOGCC. Approximately 35,000 wells are hydraulically fractured annually in the United States, and close to one million wells have been hydraulically fractured in the United States since the technique's inception, with no known harm to ground water.

It is my firmly held view and that of the IOGCC that the subject of hydraulic fracturing is adequately regulated by the states and needs no further study. In my opinion too frequent nationwide or federal study and review of critical operations like hydraulic fracturing, underground injection, and RCRA class II waste exemptions create an environment of uncertainty and litigation that inhibits real progress in sustainable resources development.

Complaints of ground water contamination attributed to hydraulic fracturing or any other oil and gas operation should continue to be investigated by the appropriate state agency or agencies to determine whether or not ground water has been affected and whether a cause and effect relationship can be established between any impacts to ground water and petroleum exploration and production activities.

Summary

The state of North Dakota and the IOGCC are firmly committed to the premise that regulation of oil and gas field activities is managed best at the state level where regional and local conditions are understood and where regulations can be tailored to fit the needs of the local environment. Federal regulatory programs have been most effective when they have been delegated to state regulatory agencies and funded through primacy programs. The primary example of this success has been the 1974 Safe Drinking Water Act (SDWA) section called the Underground Injection Control (UIC) Program. Between 1982 and 1990, twenty oil producing states applied for and received primary enforcement authority (primacy) from EPA to administer the program under Section 1425 of SDWA. Delegation of authority for this program to the states has required those with oil and gas regulatory programs to demonstrate that their programs were equally effective in protecting ground water as those promulgated and administered by EPA under Section 1422 of SDWA. Federal regulatory programs that can not be delegated to state regulatory agencies and funded through primacy programs have been a constant source of friction between regulators and it has been much more difficult to achieve compliance. The primary example of this success has been the 1990 Oil Pollution Act (OPA) and Spill Prevention Control and Countermeasure (SPCC) regulations.

Regulations alone don't begin to provide the full measure of a regulatory program. The North Dakota Oil and Gas Division of the Department of Mineral Resources utilizes 8 performance measures to monitor our activity in the areas of drilling permitting, UIC permitting, wellbore construction, well bore mechanical integrity testing, spill containment and clean up, fluid measurement, oil and gas conservation, and customer satisfaction. At least five of these measures are directly related to protection of water resources. These performance measures are backed up by a staff of field inspectors who visit the wells every day from when the drilling rig moves in until the permanent wellhead is installed and at least quarterly after that.

North Dakota has participated in numerous work groups whose purpose was the development of Best Management Practices (BMPs) and regulatory review processes. While these efforts have done a great job of documenting the evolution of technology used to address and mitigate problems real or imagined they result in snap shot views of BMP or regulatory practices at a point in time and they do not result in living documents that keep up with the industry. For example, North Dakota participated in a deep unconventional natural gas BMP work group, which finished its work just as industry focus shifted to coal bed methane, sparking another BMP work group which again finished its work just as industry focus shifted to unconventional oil and gas shale utilizing horizontal drilling and hydraulic fracturing.

Regular meetings of regulatory officials such as the IOGCC's Council of Regulatory Officials and EPA Task Force are the most effective way for regulators to keep pace with the rapid shifts in energy industry focus in real time.

TESTIMONY SUBMITTED TO THE HOUSE COMMITTEE ON OVERSIGHT AND GOVERNMENT REFORM

BY DAVID E. BOLIN, DEPUTY DIRECTOR OF THE STATE OIL AND GAS BOARD OF ALABAMA

OCTOBER 31, 2007

Good morning Chairman Waxman, Ranking Member Davis, and members of the Committee. My name is David E. Bolin. I am the Deputy Director of the State of Alabama Oil and Gas Board (Board). I am here today representing the Board, the State of Alabama, and other member states of the Interstate Oil and Gas Compact Commission (IOGCC) to express my views as a state regulator regarding the applicability of federal requirements that protect public health and the environment to oil and gas development.

The member states of the IOGCC harvest more than 99% of the oil and natural gas produced onshore in the United States. Formed by Governors in 1935, the IOGCC is a congressionally ratified interstate compact. The organization, the nation's leading advocate for conservation and wise development of domestic petroleum resources, includes 30 member and 8 associate states. The mission of the IOGCC is two-fold: to conserve our nation's oil and gas resources and to protect human health and the environment. Our current chairman is Governor Sarah Palin of Alaska.

I am here today to address two issues arising from the proposition that two provisions of the Energy Policy Act of 2005 (EPACT), Section 327 concerning hydraulic fracturing and Section 328 regarding "storm water", have resulted in harm to drinking water resources in the United States. The evidence would strongly suggest otherwise. What these two provisions accomplished was the removal of unnecessary administrative burdens on the production of oil and natural gas in the United States – nothing more.

Hydraulic Fracturing

Let me begin by addressing the hydraulic fracturing issue as it is one with which I am intimately familiar. I have been employed by the State of Alabama since July 1979 and have served in technical and supervisory roles with the Board since 1982. I am a Ground Water Hydrologist as well as a Petroleum Engineer by training. My first responsibility with the Board was to develop the State's Class II Underground Injection Control (UIC) Program, pursuant to Section 1425 of the Safe Drinking Water Act (SDWA), in order to obtain primary enforcement responsibility for that program from the U.S. Environmental Protection Agency (EPA). The EPA made a determination that our Program accomplished the objectives of the SDWA, that being to protect underground sources of drinking water from endangerment that could result from improper injection of fluids, and was therefore approved by EPA in August 1982. Since that time, I have had supervisory responsibility for the Class II UIC Program and all other ground water protection programs under the Board's jurisdiction.

Obtaining primacy for the Class II UIC Program, however, was not the beginning of the Board's ground-water protection programs. Such programs, to include the regulation and approval of hydraulic fracturing operations, have been actively implemented continually since the Board was established in 1945. The Board has a staff of geologists and petroleum engineers to provide technical expertise and to otherwise assist in its duties. In the original act establishing the Board, one of the Board's duties was to "prevent the pollution of fresh water." Protecting drinking water resources is part and parcel of every states' conservation statute: the prevention of waste and the loss of critical natural resources without economic or beneficial use. These mandates to protect drinking water and other natural resources preceded the establishment of the SDWA.

Although the Board in Alabama had been adequately protecting ground water for many years, it elected to apply for primary regulatory authority for this federal program in order to prevent dual regulatory requirements and to eliminate extended time delays associated with federal permitting and decision-making so that oil and gas development could proceed in an orderly manner and to prevent any waste that would otherwise be incurred.

Perhaps the recent history of litigation involving the issue of hydraulic fracturing would be beneficial. In 1994, a Florida-based environmental group, the Legal Environmental Assistance Foundation (LEAF), filed a petition with EPA requesting that EPA take over primacy under the State of Alabama's UIC program. LEAF contended that hydraulic fracturing associated with methane gas production was an injection under the SDWA and therefore should be subject to regulation under the State of Alabama's UIC program.

Following EPA's rejection of its petition in 1995, LEAF filed an appeal with the 11th U.S. Circuit Court of Appeals. In 1997 the 11th Circuit ruled in favor of LEAF holding that hydraulic fracturing constitutes underground injection and therefore must be regulated as such under the SWDA. The court did not address the issue of risk of harm associated with fracturing or reach any finding of actual harm to drinking water, deciding the issue strictly on the definitional issue. As a result of the court's decision and subsequent rulings, the State of Alabama in 1999 submitted a revised Class II UIC Program package consistent with the Court's rulings and subsequent orders. The EPA approved the Alabama program. A subsequent LEAF effort before the 11th U.S. Circuit arguing that EPA erred in approving the Alabama program failed as did an application for writ of certiorari before the U.S. Supreme Court.

Although EPA had never regarded hydraulic fracturing as an "underground injection" under the SDWA, and so argued before the 11th Circuit Court of Appeals, the EPA decided to let the decision stand and not appeal the court's decision. The result has been higher operating costs for producers of coalbed methane in Alabama and significantly higher administrative costs by the State of Alabama in administering its Class II UIC Program.

Thus the LEAF case launched an effort, based solely on a definitional issue and never any finding of harm, to tighten up the regulation of hydraulic fracturing nationally.

In 1999, the Ground Water Protection Council conducted a survey of state regulatory agencies regarding the inventory and extent of hydraulic fracturing in coalbed methane wells in oil and gas producing states. The principal conclusion of that survey was that "[t]here are no indications from this survey to suggest that public health is at risk as a result of the hydraulic fracturing of coalbeds used for the production of methane gas."

Additionally, in 2002, the IOGCC completed a survey of oil and natural gas producing states that provides an understanding of hydraulic fracturing and its role in the completion of oil and natural gas wells in the United States. With the committee's permission I would like to submit a copy of this survey for the record. Principal findings of this survey reveal that the technique has been in widespread, common use for nearly 60 years – the technique gained its current widespread popularity as a production technique in the 1940s. Approximately 35,000 wells are hydraulically fractured annually in this country with close to one million wells having been hydraulically fractured in the United States since the technique's inception with no documented harm to groundwater. Hydraulic fracturing has been regulated by the states since its inception. A principal focus of state oil and gas regulatory programs is on protecting ground and surface water resources. The survey reveals hydraulic fracturing of natural gas and oil wells is a process that is well understood and well regulated by the petroleum producing states.

In June 2004, EPA published a final report summarizing a study to evaluate the potential threat to underground sources of drinking water (USDWs) from the injection of hydraulic fracturing fluids into coalbed methane (CBM) production wells. In that report, EPA concluded that "additional or further study is not warranted at this time . . ." and "that the injection of hydraulic fracturing fluids into CBM wells poses minimal threat to USDWs."

EPA further stated in its summary of the study that "[i]n its review of incidents of drinking water well contamination believed to be associated with hydraulic fracturing, EPA found no confirmed cases that are linked to fracturing fluid injection into CBM wells or subsequent underground movement of fracturing fluids. Further, although thousands of CBM wells are fractured annually, EPA did not find confirmed evidence that drinking water wells have been contaminated by hydraulic fracturing fluid injection into CBM wells. Where fluids are injected, EPA believes that groundwater production, combined with mitigating effects of dilution and dispersion, adsorption, and biodegradation, minimize the possibility that chemicals included in fracturing fluids would adversely affect USDWs."

The results of these national surveys and the conclusions reached by EPA, the federal agency responsible for protecting the environment, in its study are quite significant and can not be dismissed. The states, for more than 60 years, even before the SDWA, have done an outstanding job of protecting USDWs. The regulations promulgated and enforced by our Board and our counterparts in other states have been very effective; as evidenced by the surveys and EPA's study, there have been no verified reports of contamination of USDWs by coalbed methane operations.

Alabama is a major oil and gas producing state, presently ranking tenth among the states in gas production and fifteenth in oil production. It has a broad and diverse oil and gas industry that includes onshore and offshore operations, as well as conventional and unconventional hydrocarbon resources. As such, Alabama serves as an excellent representative for all of the oil and gas producing states.

Coalbed methane has become a major contributor to Alabama's oil and gas industry in last 20 years. Since the establishment of the Board, half of the 15,600 oil and gas wells drilled in Alabama have been coalbed methane wells. Alabama has been a national leader in coalbed methane operations and was the first state to promulgate regulations addressing coalbed methane operations. In fiscal year 2007, 115.2 billion cubic feet of coalbed methane gas was produced in Alabama, representing approximately 40 percent of the state's total gas production. Similar developments in coalbed methane activity are occurring in a number of other states.

Coalbed methane production in Alabama is only economical if the coal seams can be hydraulically fractured. State regulatory agencies have a proven track record with the regulations that are in place now. These regulations have proven sufficient to adequately protect public health and the environment from hydraulic fracturing operations associated with the oil and gas development. Alabama's experience with federal requirements that were generated by the LEAF matter and ultimately required the Board to revise its Class II UIC Program have resulted in substantially increased administrative and production costs with no public health or environmental benefit.

Storm Water Discharge Management

Concerning the "storm water" issue, the issue first arose when EPA proposed a rule regarding storm water discharges when it was discovered that it could have a significant cost impact on the oil and gas industry even though the industry was not the focus of the rulemaking and even though there was no indication of inadequate regulation during construction relating to oil and natural gas production. In response, both the states, through the IOGCC, and industry engaged working groups to examine the matter.

The states, through the IOGCC, created a Storm Water Workgroup whose task was to determine how best meet EPA's needs regarding NPDES storm water management practices and to develop appropriate guidance based on existing state programs. Among other things, the workgroup did not find justification for requiring a storm water discharge permit for small exploration site activities. It found that the Federal NPDES permitting requirements were onerous and inappropriate given the level of risk to the environment. It also found that it was not feasible to develop a single standard to fit the diverse requirements for appropriate storm water discharge management throughout the United States. It concluded that states have been managing discharges at large sites and that there was no indication of a significant threat to the environment from storm water discharges by small exploration and production site activities.

The industry effort resulted in the creation of "Reasonable and Prudent Practices for Stabilization" (RAPPS) as an effective voluntary tool for reducing pollutants in storm water discharges. The industry group which created RAPPS consisted of environmental representatives from several oil and gas companies and representatives of oil and natural gas industry associations. RAPPS consisted of a compilation of the various operating practices utilized by reasonable and prudent operators in the oil and gas industry to effectively control erosion and sedimentation associated with storm water runoff from areas disturbed by clearing, grading and excavating activities related to site preparation associated oil and gas exploration, production, processing, treatment, and transmission activities.

The bottom line with respect to the storm water issue is that there is no issue. Based on the conclusions of the IOGCC study, the states were already adequately regulating this activity. Supplemented by improved industry practices based on RAPPS, the conclusion can be drawn that there was no adverse environmental impact as a result of the passage of EPACT Section 328.

A study commissioned by the U.S. Department of Energy also showed that there would likely be severe economic impacts on the oil and gas industry had the original EPA rule covered the oil and natural gas industry. It is one thing to have economic impact where an environmental harm is being mitigated; it is another when it is unnecessary.

Conclusion

The point is that America needs its domestic production of oil and natural gas, and regulations at both the federal and state level should focus on that necessary to protect the environment and public health and safety. Superfluous regulation only decreases domestic production and increases foreign imports from countries where there often exist few environmental regulations. Make no mistake, we in the U.S. are the best regulated oil and natural gas regime in the world – no other country operates under stricter environmental, health and safety regulatory oversight than do we.

Elimination of Sections 327 and 328 of EPACT would not make production of oil and natural gas in the United States an iota safer but could substantially increase domestic oil and natural gas production costs and thereby decrease domestic supply.

Thank you for the opportunity to appear here today. If we can provide any additional information, please do not hesitate to ask.

HOUSE COMMITTEE ON RESOURCES
BY VICTOR CARRILLO, CHAIRMAN, TEXAS RAILROAD COMMISSION
REPRESENTING THE INTERSTATE OIL AND GAS COMPACT COMMISSION
JULY 23, 2005

Madame Chair McMorris, Congressman Gohmert, members -- my name is Victor Carrillo and I appreciate the opportunity to testify before you. I am Chairman of the Texas Railroad Commission. In spite of the name, we oversee the Texas oil & gas, pipeline & surface mining industries, including lignite coal mines. My background is in the energy sector as a former exploration geologist/geophysicist and oil & gas attorney.

I am also here today on behalf of the Interstate Oil and Gas Compact Commission (IOGCC). IOGCC member states produce over 99% of the oil and natural gas produced onshore in the U.S. Formed in 1935, the IOGCC is a congressionally ratified interstate compact that includes 30 member and 7 associate states. Our 2005 Chairman is Governor Murkowski of Alaska. I will be 2nd Vice Chair of the organization for the upcoming year.

The mission of the IOGCC is two-fold: *to promote conservation and efficient recovery of domestic oil and natural gas resources while protecting human health and the environment.* Though many would have you believe that those dual goals are mutually exclusive – let me assure you they are not. Responsible oil & gas exploration and development and stewardship of our land and water resources can both be accomplished simultaneously. We see it done in Texas day in and day out.

In Texas, we are quite proud of our ongoing role as the premier energy producing state in the nation. Texas is still the #1 producing state for oil and natural gas. We produce about 6 Trillion Cubic Feet of natural gas per year, which represents over 25% of total U.S. demand for the clean burning energy source. We are also the 5th largest producer of coal in the nation.

As of one week ago, Texas had 619 active oil & gas rigs operating in the state -- representing almost 50% of all land rigs in the nation. And as a nation as we move to establish more LNG (liquefied natural gas) facilities, I'm proud to say that four new onshore LNG facilities have already been given the green light by FERC along our Texas Gulf Coast.

Texas has the most extensive pipeline infrastructure in the nation with over 250,000 miles of underground petroleum pipelines throughout the state. There are 26 refineries in the state with a total refining capacity of over 4 million barrels per day, equaling over 25% of the nation's total refining capacity. Texas is still the preeminent energy producing and refining state in the nation.

In February, I testified in Washington alongside Governor Frank Murkowski of Alaska in support of the Energy Policy Act of 2005. I continue to believe that the House version is a very good first step to help ensure our nation's future energy security by helping to maximize the production of our domestic petroleum resource.

Turning to today's topic, no country in the world produces its oil, gas and coal to higher environmental standards. Texas and the other energy producing states are proud of these environmental standards for we believe that we have a stewardship responsibility for our land and water resources. But the ever growing and often Draconian federal environmental laws and regulations threaten future exploration, production, and refining capacity.

I'd also like to point out that while Texas is the top oil and gas producing state, Texas also ranks first in overall consumption of petroleum, natural gas, coal, and electricity. So we share the national concern for reliable energy supply sources at reasonable and stable prices. A secure source of domestically produced oil, natural gas, and coal is in the best interest of all – producing and consuming states alike.

Recognizing that my time is limited, let me address just a few specific hot topics.

Stormwater Runoff.
I am concerned with EPA rulemaking under the NPDES Stormwater Permit Coverage for Small Oil & Gas Construction Activities which would potentially require a stormwater permit of oil & gas operators for activities affecting one acre or more, particularly with their interpretation of "common plan of development" concept in the Construction General Permit. EPA's rule would improperly seek to treat oil & gas activities activities like residential/commercial construction activities – and they are not the same. In residential/commercial construction projects, there is often a common plan of development that would impact an aggregated area of disturbance. With oil & gas exploration, there is no guarantee of success of the first well, much less any subsequent wells. In fact, let's say you drill a $2 million dollar exploratory well and you find nothing or at least nothing that is economic to produce, then any plans for future wells in that immediate area project will likely never come to fruition. For the oil & gas producer, there simply is no common plan of development in the vast majority of cases.

A recent independent economic analysis completed for the U.S. Department of Energy (*Estimated Economic Impacts of Proposed Storm Water Discharge Requirement on Oil & Gas Industry Report* from Advance Resources International, Inc. to U.S. DOE Office of Fossil Fuels, Dec. 2004) estimated that just this one EPA regulatory change could cost the country from 1.3 to 3.9 billion barrels of domestic oil production and 15 to 45 trillion cubic feet of domestic gas production over the next 20 years. To put that into context, and taking the median of those numbers, that represents over five years of Texas natural gas production and over seven years of Texas oil production that would be lost.

Hydraulic Fracturing
There is a current effort in the context of the Energy Bill seeking to broadly regulate hydraulic fracturing under the Safe Drinking Water Act for the very first time ever. Hydraulic fracturing is a technique developed in oil & gas exploration to fracture deep underground oil & gas bearing strata, thus releasing more of the oil & gas to be produced. The technique has been safely and successfully used in states like Texas for decades without any known negative impact to drinking water supplies. In the vast majority of wells that have used these techniques in Texas, the fracture zone is thousands of feet deep, well below any possible contact with the drinking quality water, which is generally limited to a few hundred feet from the surface.

Technological advancements allow industry to find & produce more domestic oil & gas, more efficiently, where we already know it to exist. It is technological advancements like hydraulic fracturing, that have allowed the Barnett Shale Gas Play near Dallas/Ft. Worth to develop into the largest producing gas field in Texas and one of the hottest gas plays in the nation. Without the ability to use hydraulic fracture techniques in the Barnett Shale, this huge gas deposit would not be economic to produce.

A one-size fits all, federally mandated, EPA administered regulatory approach in this issue unnecessarily trammels state rights to oversee this activity in our state, by our own more flexible and appropriate means. State programs like ours in Texas have for almost 100 years protected precious ground water resources while allowing domestic oil and gas production to supply our national energy needs.

Refining (Downstream).
There has been no major new refinery built in the U.S. since 1976. Did you know that now, in addition to importing almost 60% of the oil (unrefined) that we need, we are now importing about 10% of the refined gasoline that we need. The fact is that there is limited domestic refining capacity. We had over 300 U.S.

refineries in 1980. At the end of 2003, there were about 149 – a 50% reduction. Most are running at near capacity.

Why have no U.S. based refineries been built in almost three decades? While NIMBY plays an important role, so do the incredibly stringent environmental controls (NEPA, Clean Air Act, Clean Water Act, RCRA, etc.) that apply to new major construction. Some estimates suggest that it would take several hundred permits and at least $2 billion to build a new refinery – perhaps half of that cost attributable to the regulations directly

In the last decade alone, industry has invested almost $50 billion in environmental improvements to existing facilities. And we wonder why gasoline prices are at their current prices.

Access to Public Lands.
One final issue I will mention is the need to encourage opening up areas currently off limits to oil and gas exploration – areas in the intermontane west, in Alaska, and in our Outer Continental Shelf (OCS) regions. And pertinent to this task force, we should also seek to streamline areas that are already open to exploration but that are frequently tied up in unnecessarily complicated environmental requirements, particularly on federal lands.

In summary, I believe that we would all do well to support the general notion that "government that governs least governs best." No doubt, certain environmental laws and regulations are essential to protect the public health and safety. However, many of these environmental laws far exceed their original intent. To the degree we can, we must reel in and restrain government regulations that all too often are overbroad, complex, and costly and that stifle innovation, ingenuity & investment growth in private sector. When the federal government does pass a law or regulation, it should be simple, clear, understandable, limited in scope, reasonable, practical, & pass the common sense test.

Finally, let me emphasize the need for flexible regulatory oversight and management tools as opposed to rigid, Draconian measures that simply add cost and delay, and ultimately limit domestic energy production at the very time that we need to be more, not less, energy self sufficient.

Thank you so much for the opportunity to appear before you today. If I can provide any additional information, please just ask. I personally stand ready to assist you in any energy-related matter in which you are interested.

Tom Richmond of Billings is division administrator of the Montana Board of Oil and Gas Conservation in the Department of Natural Resources and Conservation.

Guest Opinion: Hydraulic fracturing in oil fields works safely for Montana

By Tom Richmond

Hydraulic fracturing has been used by the oil and gas industry for 60 years to increase the productivity of wells and recover oil and gas. Many of Montana's gas wells and essentially all our Bakken oil wells would not be economically viable to drill without hydraulic fracturing, resulting in a loss of at least $4 billion worth of oil and $350 million of state revenues. Along with improved drilling technology, hydraulic fracturing has doubled Montana's oil and gas production.

Recently, the safety of hydraulic fracturing has been called into question by organizations trying to convince Congress and the Environmental Protection Agency to establish or broaden federal regulations. These organizations are using fear tactics - unsubstantiated claims of groundwater contamination by dangerous chemicals - to make their case. The truth is that hydraulic fracturing is already regulated appropriately by the states. Thousands of wells in Montana and about 1 million wells nationwide have been fractured with no groundwater contamination reported.

Protective barriers

Hydraulic fracturing is not a haphazard process. Engineers use computer models to custom-design each individual fracture treatment, taking into account the physical and chemical properties of the rock, the fluids contained within that rock, and the mechanical condition of the well. The computer models are used to design an effective treatment that stays within the targeted rock formation thousands of feet underground. Additionally, the wells are designed and constructed to provide at least three protective barriers that prevent water contamination.

The primary products used in Montana's hydraulic fractures are sand and a fluid to carry the sand. The most common carrier fluids are either nitrogen foam or gelled water. The products that cause the nitrogen to foam are the basic ingredients in household cleaning agents, such as borax or detergent; the gelling agents are similar to those used in making gelatin dessert or soft-serve ice cream. The EPA has identified diesel fuel as a potential health hazard, but it is seldom used in Montana.

The geology of Montana provides further protection from contamination. Groundwater that furnishes drinking water and conventional gas and oil reservoirs do not inhabit the same underground territory - they are typically many thousands of feet apart and separated by numerous impermeable layers.

Every oil- and gas-producing state has multiple agencies that regulate exploration and development. In addition to the Board of Oil and Gas Conservation, the Montana

Department of Environmental Quality and Montana Department of Natural Resources and Conservation have roles in oil and gas operations, water quality and water quantity regulation, as well as land use and leasing roles. The U.S. Occupational Safety and Health Administration, U.S. Department of Transportation and EPA oversee some aspect of the transportation, use and proper disposal of any substances used in oil and gas production; the U.S. Bureau of Land Management has similar responsibility on federally owned land. Requiring additional oversight by still more federal agencies would be costly and redundant and add little to the substantial regulatory network already in place.

No documented harm

Approximately 35,000 wells are hydraulically fractured annually in the United States; about 1 million wells have been hydraulically fractured in the U.S. since the technique was first developed, with no documented harm to groundwater. Hydraulic fracturing is essential for developing our abundant and environmentally desirable natural gas resources, and the safety and effectiveness of this process are proven every day.

IOGCC/MR Safeguards to HF 10 09

SAFEGUARDS UTILIZED BY STATE OIL AND GAS CONSERVATION AGENCIES FOR PROTECTING FROM POTENTIAL ADVERSE EFFECTS ON WATER FROM HYDRAULIC FRACTURING, 2009

1. All states have regulations addressing casing and cementing requirements. Proper casing and cementing ensures that fracture fluids injected into the formation being fractured remain in that formation.
2. Oil and gas conservation experts review the geologic information to ensure there is an impervious stratum above the formation fractured.
3. Many states ban hydraulic fracturing shallower than a particular depth, e.g., in Alabama, hydraulic fracturing is banned at a depth shallower than 300 feet.
4. Some states require a water well survey to be performed for water wells within a quarter mile of the well on which a hydraulic fracturing operation is being conducted. Then these states consider the depth at which hydraulic fracturing is allowed.
5. Some states require a statement from the operator that fracture fluid utilized in hydraulic fracturing does not contain deleterious substances.
6. All states utilize inspectors, who observe the actual hydraulic fracturing operation to ensure that the operation is conducted properly so that no harm is caused.
7. When hydraulic fracturing operations are conducted, virtually all of the fracturing fluid is recovered to the surface and does not remain in the well. The EPA report addresses this recovery of fracture fluid.
8. All states have enforcement authority to ensure compliance with applicable statutes and regulations.
9. The fracture fluid that is recovered to the surface is disposed in accordance with accepted and regulated disposal techniques.

IOGCC 75 Anniversary
INTERSTATE
Oil & Gas
COMPACT COMMISSION

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North Dakota
Ohio
Oklahoma
Pennsylvania
South Dakota
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Virginia
West Virginia
Wyoming

February 23, 2009

President Barack Obama
The White House
1600 Pennsylvania Avenue NW
Washington, DC 20500

Dear Mr. President:

As the executive director of the Interstate Oil and Gas Compact Commission (IOGCC), I am forwarding resolutions approved by the IOGCC member states at our recent Annual Meeting. As you can see from these resolutions, the nation's oil and gas producing states have concerns about the need for a strong, active national energy policy.

The attention of Congress on energy policy recently has largely overlooked domestic petroleum, the nation's most important energy source. The states want to work with you to be a part of the energy solution. In addition, we hope for expanded dialogue on energy issues, particularly manpower, research and production concerns.

I welcome any opportunity to work with and assist you on matters related to our nation's energy resources. Please contact me if I can provide you or your staff with more background on energy policy matters. My phone number is (405) 525-3556, extension 200, and my e-mail address is mike.smith@iogcc.state.ok.us.

Sincerely,

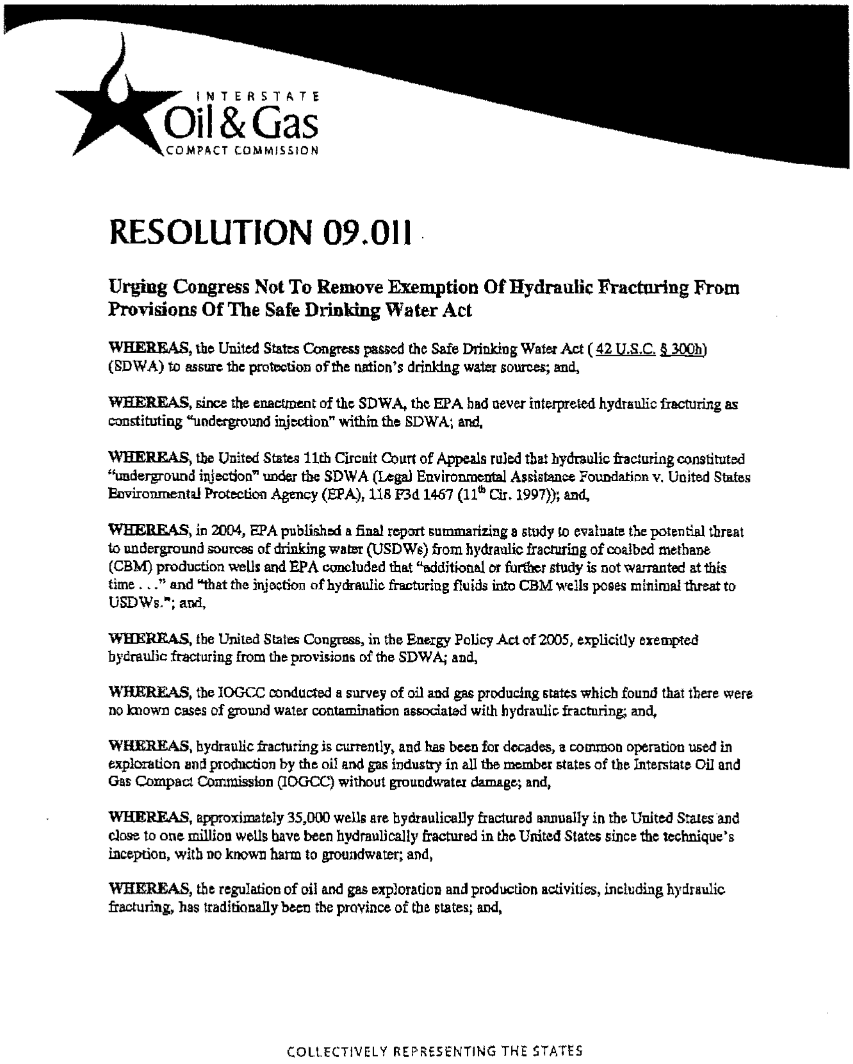
Carl Michael Smith
Executive Director
Interstate Oil and Gas Compact Commission

MS/mo

Enclosures:

09.011 Urging Congress Not To Remove Exemption Of Hydraulic Fracturing From Provisions Of The Safe Drinking Water Act
08.111 Supporting Congressional Appropriation for Geological and Geophysical Data Preservation under Provisions of the Energy Policy Act of 2005 (Reauthorized)
08.112 Urging The Continued Development Of An Effective National Energy Policy (Reauthorized)
08.113 Continuing Policy On The Issue Of Carbon Storage In Underground Geologic Formations (Reauthorized)
08.114 Identifying and Promoting Energy Manpower Needs (Reauthorized)
08.115 Requesting Funding for the Reclamation of Orphaned Well Sites (Reauthorized)
08.116 Encouraging the Full Funding of the Land and Water Conservation Fund State Assistance Program (New)

COLLECTIVELY REPRESENTING THE STATES



INTERSTATE
Oil & Gas
COMPACT COMMISSION

RESOLUTION 09.011

Urging Congress Not To Remove Exemption Of Hydraulic Fracturing From Provisions Of The Safe Drinking Water Act

WHEREAS, the United States Congress passed the Safe Drinking Water Act (42 U.S.C. § 300h) (SDWA) to assure the protection of the nation's drinking water sources; and,

WHEREAS, since the enactment of the SDWA, the EPA had never interpreted hydraulic fracturing as constituting "underground injection" within the SDWA; and,

WHEREAS, the United States 11th Circuit Court of Appeals ruled that hydraulic fracturing constituted "underground injection" under the SDWA (Legal Environmental Assistance Foundation v. United States Environmental Protection Agency (EPA), 118 F3d 1467 (11th Cir. 1997)); and,

WHEREAS, in 2004, EPA published a final report summarizing a study to evaluate the potential threat to underground sources of drinking water (USDWs) from hydraulic fracturing of coalbed methane (CBM) production wells and EPA concluded that "additional or further study is not warranted at this time . . ." and "that the injection of hydraulic fracturing fluids into CBM wells poses minimal threat to USDWs."; and,

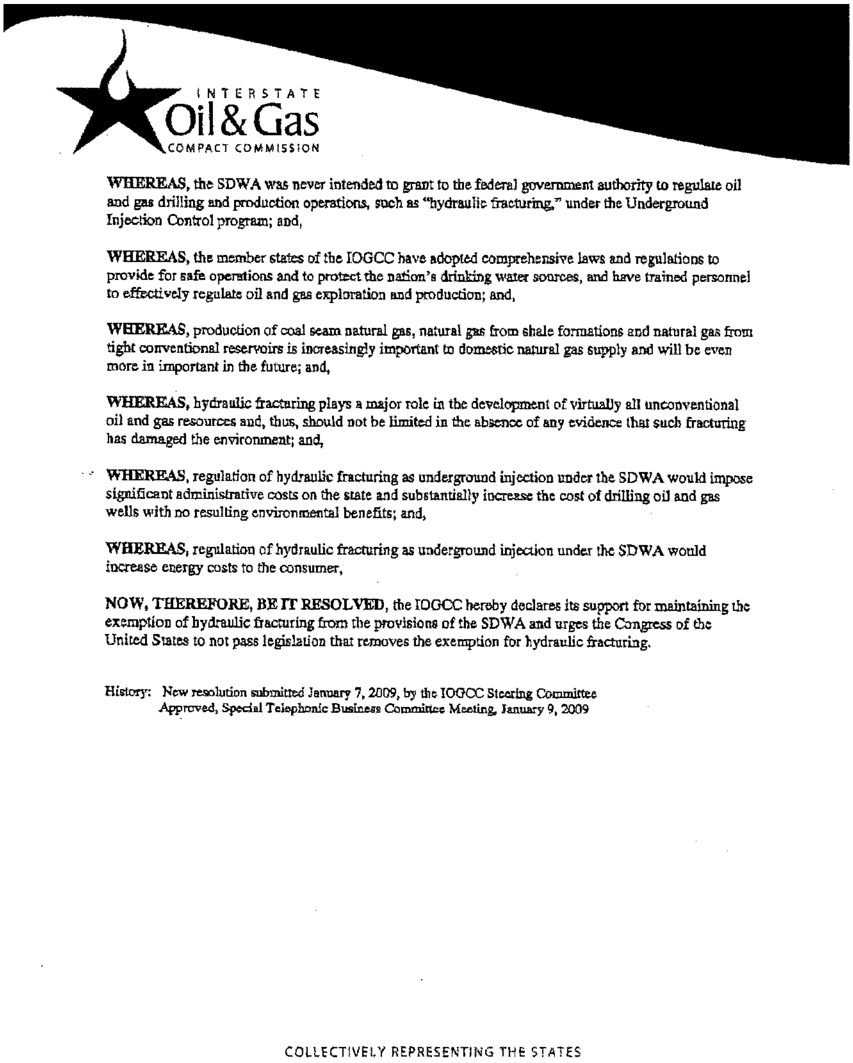
WHEREAS, the United States Congress, in the Energy Policy Act of 2005, explicitly exempted hydraulic fracturing from the provisions of the SDWA; and,

WHEREAS, the IOGCC conducted a survey of oil and gas producing states which found that there were no known cases of ground water contamination associated with hydraulic fracturing; and,

WHEREAS, hydraulic fracturing is currently, and has been for decades, a common operation used in exploration and production by the oil and gas industry in all the member states of the Interstate Oil and Gas Compact Commission (IOGCC) without groundwater damage; and,

WHEREAS, approximately 35,000 wells are hydraulically fractured annually in the United States and close to one million wells have been hydraulically fractured in the United States since the technique's inception, with no known harm to groundwater; and,

WHEREAS, the regulation of oil and gas exploration and production activities, including hydraulic fracturing, has traditionally been the province of the states; and,



WHEREAS, the SDWA was never intended to grant to the federal government authority to regulate oil and gas drilling and production operations, such as "hydraulic fracturing," under the Underground Injection Control program; and,

WHEREAS, the member states of the IOGCC have adopted comprehensive laws and regulations to provide for safe operations and to protect the nation's drinking water sources, and have trained personnel to effectively regulate oil and gas exploration and production; and,

WHEREAS, production of coal seam natural gas, natural gas from shale formations and natural gas from tight conventional reservoirs is increasingly important to domestic natural gas supply and will be even more in important in the future; and,

WHEREAS, hydraulic fracturing plays a major role in the development of virtually all unconventional oil and gas resources and, thus, should not be limited in the absence of any evidence that such fracturing has damaged the environment; and,

WHEREAS, regulation of hydraulic fracturing as underground injection under the SDWA would impose significant administrative costs on the state and substantially increase the cost of drilling oil and gas wells with no resulting environmental benefits; and,

WHEREAS, regulation of hydraulic fracturing as underground injection under the SDWA would increase energy costs to the consumer,

NOW, THEREFORE, BE IT RESOLVED, the IOGCC hereby declares its support for maintaining the exemption of hydraulic fracturing from the provisions of the SDWA and urges the Congress of the United States to not pass legislation that removes the exemption for hydraulic fracturing.

History: New resolution submitted January 7, 2009, by the IOGCC Steering Committee
Approved, Special Telephonic Business Committee Meeting, January 9, 2009

ACT# 2009-241

HJR254

108408-2

By Representatives Allen, Buskey, Guin, Scott, McClurkin, Mask and Harper

RFD: Rules

First Read: 03-MAR-09

RECEIVED
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ENROLLED, House Joint Resolution,

REQUESTING CONGRESS TO PRESERVE THE PRIMACY OF THE STATE OIL AND GAS BOARD OF ALABAMA TO REGULATE HYDRAULIC FRACTURING IN COMPLIANCE WITH DECADES OLD STATE REGULATIONS AND NOT TO ENACT ANY FUTURE LEGISLATION THAT WOULD REMOVE THIS PRIMACY.

WHEREAS, the regulation of oil and gas exploration and production activities, including hydraulic fracturing, has traditionally been the province of the states; and

WHEREAS, approximately 35,000 wells are hydraulically fractured annually in the United States and nearly 1,000,000 wells have been hydraulically fractured in the United States since the technique's inception, with no known harm to groundwater; and

WHEREAS, production of coal seam natural gas, natural gas from shale formations, and natural gas from tight conventional reservoirs is increasingly important to domestic natural gas supply and will be more important in the future; and

WHEREAS, Alabama was a pioneer in both the development of coal seam natural gas and the hydraulic fracturing technology necessary to make production economic; and

WHEREAS, coal seam gas now accounts for about 40 percent of all natural gas produced in Alabama because of successful implementation of hydraulic fracturing; and

WHEREAS, domestic production of natural gas will ensure that the United States continues on the path to energy independence; and

WHEREAS, hydraulic fracturing plays a major role in the development of virtually all unconventional oil and gas resources and, thus, should not be limited in the absence of any evidence that hydraulic fracturing has damaged the environment; and

WHEREAS, the United States Congress passed the Safe Drinking Water Act, 42 U.S.C. § 300h (SDWA) to assure the protection of the nation's drinking water sources; and

WHEREAS, since the enactment of the SDWA, the United States Environmental Protection Agency (EPA) has never interpreted hydraulic fracturing as constituting "underground injection" within the SDWA; and

WHEREAS, in 2004, the EPA published a final report summarizing a study to evaluate the potential threat to underground sources of drinking water (USDWs) from hydraulic fracturing of coalbed methane (CBM) production wells and concluded that "additional or further study is not warranted at this time" and that "the injection of hydraulic fracturing fluids into CBM wells poses minimal threat to USDWs"; and

WHEREAS, the United States Congress, in the Energy Policy Act of 2005, explicitly exempted hydraulic fracturing from the provisions of the SDWA; and

WHEREAS, the Interstate Oil and Gas Compact Commission (IOGCC) conducted a survey of oil and gas producing states and found that there were no known cases of ground water contamination associated with hydraulic fracturing; and

WHEREAS, hydraulic fracturing is currently, and has been for decades, a common operation used in exploration and production by the oil and gas industry in all the member states of the IOGCC without groundwater damage; and

WHEREAS, the SDWA has never intended to grant to the federal government authority to regulate oil and gas drilling and production operations, such as "hydraulic fracturing," under the Underground Injection Control Program; and

WHEREAS, the member states of the IOGCC have adopted comprehensive laws and regulations to provide for safe operations and to protect the nation's drinking water sources, and have trained personnel to effectively regulate oil and gas exploration and production; and

WHEREAS, regulation of hydraulic fracturing as underground injection under the SDWA would impose significant administrative costs on the state and substantially increase the cost of drilling oil and gas wells with no resulting environmental benefits; and

WHEREAS, the United States Department of Energy recently studied the impacts of subjecting hydraulic fracturing to the EPA Underground Injection Control Program and projected it would add an average of more than $100,000 in costs to each new natural gas well requiring fracturing, resulting in billions of dollars in deferred investment, reductions of 35 percent to 50 percent in new drilling for unconventional natural gas, foregone reserve additions of as much as 50 trillion cubic feet of natural gas, and foregone royalties from gas of nearly 50 billion dollars over 25 years; and

WHEREAS, regulation of hydraulic fracturing as underground injection under the SDWA would increase energy costs to the consumer; now therefore,

BE IT RESOLVED BY THE LEGISLATURE OF ALABAMA, BOTH HOUSES THEREOF CONCURRING, That the Alabama Legislature hereby declares its support for the State Oil and Gas Board of Alabama maintaining primacy for the regulation of hydraulic fracturing and urges the Congress of the United States not to pass legislation that would remove state primacy for hydraulic fracturing by regulating the practice under the Safe Drinking Water Act.

BE IT FURTHER RESOLVED, That copies of this resolution be sent forthwith to the President of the United States, to the President of the Senate, and the Speaker of the

House of Representatives of the United States Congress and to the members of the Alabama Congressional Delegation.

Speaker of the House of Representatives

Jim Folsom Jr

President and Presiding Officer of the Senate

House of Representatives

I hereby certify that the within Act originated in and was adopted by the House 05-MAR-09.

Greg Pappas
Clerk

Senate 07-APR-09 Adopted

APPROVED April 20, 2009
TIME 9:10 a.m
Bob Riley
GOVERNOR

Alabama Secretary Of State
Act Num....: 2009-241
Bill Num...: HJR-254
Recv'd 04/20/09 03:01pmJJB

HLS 09RS-1501 4/22/09 9:36 AM

Regular Session, 2009

HOUSE CONCURRENT RESOLUTION NO.

BY REPRESENTATIVE HARRISON

ENERGY/DRILLING: Memorializes Congress to maintain the exemption from the Safe Drinking Water Act for hydraulic fracturing

To memorialize the United States Congress to take such actions as are necessary to preserve and maintain the exemption from the Safe Drinking Water Act for hydraulic fracturing.

WHEREAS, the Safe Drinking Water Act (SDWA) was originally passed by Congress in 1974 to protect public health by regulating the nation's public drinking water supply; and

WHEREAS, since the 1974 enactment of the Safe Drinking Water Act, the Environmental Protection Agency (EPA) has never interpreted hydraulic fracturing as constituting "underground injection" within the definitions of the SDWA; and

WHEREAS, in 2004, the EPA published a final report summarizing a study that evaluated the potential threat to underground drinking water sources from hydraulic fracturing of coal bed methane production wells and the EPA concluded that "the injection of hydraulic fracturing fluids into coal bed methane wells poses minimal threat" to underground sources of drinking water and that "additional or further study is not warranted at this time . . ."; and

WHEREAS, in the Energy Policy Act of 2005, the United States Congress explicitly exempted hydraulic fracturing from the provisions of the Safe Drinking Water Act; and

WHEREAS, the Interstate Oil and Gas Compact Commission (IOGCC) conducted a survey of oil and gas producing states which found that there were no known cases of groundwater contamination associated with hydraulic fracturing; and

WHEREAS, hydraulic fracturing is currently, and has been for decades, a common practice used in exploration and production by the oil and gas industry in all IOGCC member states without groundwater damage; and

WHEREAS, approximately 35,000 wells are hydraulically fractured in the United States annually, and close to a million wells have been hydraulically fractured in the United States since the technique's inception, all with no known harm to groundwater; and

WHEREAS, the regulation of oil and gas exploration and production activities, including hydraulic fracturing, has traditionally been the responsibility of the states and the Safe Drinking Water Act was never intended to grant to the federal government authority to regulate oil and gas drilling and production operations, such as "hydraulic fracturing," which is regulated under the Underground Injection Control program; and

WHEREAS, the individual member states of the IOGCC have adopted comprehensive laws and regulations to provide safe operations and to protect the nation's drinking water sources, and have trained personnel to effectively regulate oil and gas exploration and production; and

WHEREAS, production of coal seam natural gas, natural gas from shale formations, and natural gas from tight conventional reservoirs is becoming increasingly important to our domestic natural gas supply and will be even more important in the future; and

WHEREAS, continued and expanded domestic production of natural gas will help ensure that the United States continues on the path to energy independence; and

WHEREAS, hydraulic fracturing plays a major role in the development of virtually all unconventional oil and gas resources and regulation of hydraulic fracturing as underground injection under the Safe Drinking Water Act would impose significant administrative costs on the states and substantially increase the cost of drilling oil and gas wells with no resulting environmental benefits; and

WHEREAS, in addition to increasing the costs both to the producers of oil and gas resources and the states for regulation of hydraulic fracturing as underground injection under the SDWA, the costs to the consumer would also increase if hydraulic fracturing was limited or prohibited.

THEREFORE, BE IT RESOLVED that the Legislature of Louisiana does hereby memorialize the United States Congress to take such actions as are necessary to preserve and maintain the exemption from the Safe Drinking Water Act for hydraulic fracturing.

BE IT FURTHER RESOLVED that a copy of this Resolution be transmitted to the presiding officers of the Senate and the House of Representatives of the Congress of the United States of America and to each member of the Louisiana congressional delegation.

DIGEST

The digest printed below was prepared by House Legislative Services. It constitutes no part of the legislative instrument. The keyword, one-liner, abstract, and digest do not constitute part of the law or proof or indicia of legislative intent. [R.S. 1:13(B) and 24:177(E)]

Harrison No.

Memorialize the United States Congress to take such actions as are necessary to preserve and maintain the exemption from the Safe Drinking Water Act for hydraulic fracturing.

Sixty-first Legislative Assembly of North Dakota
In Regular Session Commencing Tuesday, January 6, 2009

SENATE CONCURRENT RESOLUTION NO. 4020
(Senators O'Connell, Grindberg, Wardner)
(Representatives Berg, S. Meyer, Skarphol)

A concurrent resolution urging Congress to preserve the exemption of hydraulic fracturing from the provisions of the Safe Drinking Water Act and to not enact legislation that removes the exemption for hydraulic fracturing.

WHEREAS, Congress enacted the Safe Drinking Water Act to ensure the protection of the nation's drinking water sources; and

WHEREAS, since enactment of the Safe Drinking Water Act, the Environmental Protection Agency has never interpreted hydraulic fracturing as constituting "underground injection" under the Safe Drinking Water Act; and

WHEREAS, in 2004 the Environmental Protection Agency published a final report summarizing a study to evaluate the potential threat to underground sources of drinking water from hydraulic fracturing of coalbed methane production wells and the Environmental Protection Agency concluded that "additional or further study is not warranted at this time..." and that "the injection of hydraulic fracturing fluids into coalbed methane wells poses minimal threat to the underground sources of drinking water"; and

WHEREAS, Congress, in the Energy Policy Act of 2005, explicitly exempted hydraulic fracturing from the provisions of the Safe Drinking Water Act; and

WHEREAS, the Interstate Oil and Gas Compact Commission conducted a survey of North Dakota and other oil and gas-producing states which found that there were no known cases of ground water contamination associated with hydraulic fracturing; and

WHEREAS, hydraulic fracturing is currently, and has been for decades, a common operation used in exploration and production by the oil and gas industry in North Dakota and all the member states of the Interstate Oil and Gas Compact Commission; and

WHEREAS, approximately 35,000 wells are hydraulically fractured annually in the United States, and close to one million wells have been hydraulically fractured in the United States since the technique's inception, with no known harm to ground water; and

WHEREAS, the regulation of oil and gas exploration and production activities, including hydraulic fracturing, has traditionally been the province of the states; and

WHEREAS, the success of the Bakken Formation and development of domestic oil and gas resources across the United States has been revitalized by technological advancements which include the ability to fracture and stimulate challenging geological formations, such as the Bakken Formation in North Dakota, and thus should not be limited in the absence of any evidence that such fracturing has damaged the environment; and

WHEREAS, the Safe Drinking Water Act was never intended to grant to the federal government authority to regulate oil and gas drilling and production operations, such as "hydraulic fracturing," under the underground injection control program; and

WHEREAS, North Dakota and other member states of the Interstate Oil and Gas Compact Commission have adopted comprehensive laws and regulations to provide for safe operations and to protect the nation's drinking water sources and have trained personnel to effectively regulate oil and gas exploration and production; and

WHEREAS, domestic production of natural gas will ensure that the United States continues on the path to energy independence; and

WHEREAS, regulation of hydraulic fracturing as underground injection under the Safe Drinking Water Act would impose significant administrative costs on the state, substantially increase the cost of drilling oil and gas wells, and potentially stop the development of our state's valuable natural resources, including the Bakken and other formations with no resulting environmental benefits; and

WHEREAS, regulation of hydraulic fracturing as underground injection under the Safe Drinking Water Act would increase energy costs to the consumer;

NOW, THEREFORE, BE IT RESOLVED BY THE SENATE OF NORTH DAKOTA, THE HOUSE OF REPRESENTATIVES CONCURRING THEREIN:

That the Sixty-first Legislative Assembly urges the Congress of the United States to preserve the exemption of hydraulic fracturing from the provisions of the Safe Drinking Water Act and urges the Congress of the United States not to enact legislation that removes the exemption for hydraulic fracturing; and

BE IT FURTHER RESOLVED, that the Secretary of State forward copies of this resolution to the President of the United States, to the President of the Senate and the Speaker of the House of Representatives of the United States, and to each member of the North Dakota Congressional Delegation.

President of the Senate

Speaker of the House

Secretary of the Senate

Chief Clerk of the House

Filed in this office this ____________ day of ______________________________________, 2009,

at ________ o'clock ______ M.

Secretary of State

STATE OF OKLAHOMA

1st Session of the 52nd Legislature (2009)

HOUSE CONCURRENT
RESOLUTION 1012

By: Thompson of the House

and

Bingman of the Senate

AS INTRODUCED

A Concurrent Resolution expressing support for the preservation of the exemption for hydraulic fracturing from the Safe Drinking Water Act; urging Congress not to pass legislation that removes the exemption; and directing distribution.

WHEREAS, the United States Congress passed the Safe Drinking Water Act to assure the protection of the nation's drinking water sources; and

WHEREAS, since the enactment of the Safe Drinking Water Act, the United States Environmental Protection Agency has never interpreted hydraulic fracturing as constituting "underground injection" under the Act; and

WHEREAS, in the case of *Legal Environmental Assistance Foundation v. United States Environmental Protection Agency (EPA)*, 118 F3d 1467 (11th Cir. 1997), the United States 11th Circuit Court of Appeals ruled contrary to argument of the United States Environmental Protection Agency that hydraulic fracturing constituted "underground injection" under the Safe Drinking Water Act; and

WHEREAS, in 2004, the Environmental Protection Agency published a final report summarizing a study to evaluate the potential threat to underground sources of drinking water from hydraulic fracturing of coalbed methane production wells and concluded that "additional or further study is not warranted at this time . . ." and "that the injection of hydraulic fracturing fluids into coalbed methane wells poses minimal threat to underground sources of drinking water"; and

WHEREAS, the United States Congress, in the Energy Policy Act of 2005, explicitly exempted hydraulic fracturing from the provisions of the Safe Drinking Water Act; and

WHEREAS, the Interstate Oil and Gas Compact Commission conducted a survey of oil- and gas-producing states and found that there were no known cases of groundwater contamination associated with hydraulic fracturing; and

WHEREAS, hydraulic fracturing is currently, and has been for decades, a common operation used in exploration and production by the oil and gas industry in all the member states of the Interstate Oil and Gas Compact Commission without groundwater damage; and

WHEREAS, approximately 35,000 wells are hydraulically fractured annually in the United States and close to one million wells have been hydraulically fractured in the United States since the inception of the technique, with no known harm to groundwater; and

WHEREAS, the regulation of oil and gas exploration and production activities, including hydraulic fracturing, has traditionally been the province of the states; and

WHEREAS, the Safe Drinking Water Act was never intended to grant to the federal government authority to regulate oil and gas drilling and production operations, such as hydraulic fracturing, under the Underground Injection Control program; and

WHEREAS, the member states of the Interstate Oil and Gas Compact Commission have adopted comprehensive laws and regulations to provide for safe operations and to protect the drinking water sources of the nation, and have trained personnel to effectively regulate oil and gas exploration and production; and

WHEREAS, production of coal-seam natural gas, natural gas from shale formations and natural gas from tight conventional reservoirs is increasingly important to domestic natural gas supply and will be even more important in the future; and

WHEREAS, domestic production of natural gas will ensure that the United States continues on the path to energy independence; and

WHEREAS, hydraulic fracturing plays a major role in the development of virtually all unconventional oil and gas resources and should not be limited in the absence of any evidence that hydraulic fracturing has damaged the environment; and

WHEREAS, regulation of hydraulic fracturing as underground injection under the Safe Drinking Water Act would impose significant administrative costs on the state and substantially increase the cost of drilling oil and gas wells with no resulting environmental benefits; and

WHEREAS, the regulation of hydraulic fracturing as underground injection under the Safe Drinking Water Act would increase energy costs to the consumer.

NOW, THEREFORE, BE IT RESOLVED BY THE HOUSE OF REPRESENTATIVES OF THE 1ST SESSION OF THE 52ND OKLAHOMA LEGISLATURE, THE SENATE CONCURRING THEREIN:

THAT the Oklahoma Legislature hereby declares its support for maintaining the exemption of hydraulic fracturing from the provisions of the Safe Drinking Water Act and urges the Congress of the United States not to pass legislation that removes the exemption for hydraulic fracturing.

THAT a copy of this resolution be distributed to the President of the United States, the President of the United States Senate, the Speaker of the United States House of Representatives, and to each member of the Oklahoma Congressional Delegation.

52-1-7241 KB 03/02/09

HYDRAULIC FRACTURING JOINT RESOLUTION

2009 GENERAL SESSION
STATE OF UTAH
Chief Sponsor: David P. Hinkins
House Sponsor: Michael E. Noel

LONG TITLE

General Description:

This joint resolution of the Legislature urges Congress to preserve the exemption for hydraulic fracturing in the Safe Drinking Water Act and to refrain from passing legislation that would remove the hydraulic fracturing exemption.

Highlighted Provisions:

This resolution:

- expresses support for maintaining the exemption of hydraulic fracturing from the provisions of the Safe Drinking Water Act; and
- urges Congress to refrain from passing legislation that would remove the exemption for hydraulic fracturing.

Special Clauses:

None

Be it resolved by the Legislature of the state of Utah:

WHEREAS, the United States Congress passed the Safe Drinking Water Act (Act) to assure the protection of the nation's drinking water sources;

WHEREAS, since the enactment of the Act, the Environmental Protection Agency (EPA) has never interpreted hydraulic fracturing as constituting "underground injection" within the Act;

WHEREAS, in 2004, the EPA published a final report summarizing a study to evaluate the potential threat to underground sources of drinking water from hydraulic fracturing of coal bed methane production wells and the EPA concluded that "additional or further study is not warranted at this time . . ." and "that the injection of hydraulic fracturing fluids into coal bed methane wells poses minimal threat" to underground sources of drinking water;

WHEREAS, in the Energy Policy Act of 2005, the United States Congress explicitly exempted hydraulic fracturing from the provisions of the Act;

WHEREAS, the Interstate Oil and Gas Compact Commission (IOGCC) conducted a survey of oil and gas producing states which found that there were no known cases of groundwater contamination associated with hydraulic fracturing;

WHEREAS, hydraulic fracturing is currently, and has been for decades, a common operation used in exploration and production by the oil and gas industry in all the member states of the IOGCC without groundwater damage;

WHEREAS, approximately 35,000 wells are hydraulically fractured in the United States annually, and close to 1,000,000 wells have been hydraulically fractured in the United States since the technique's inception, with no known harm to groundwater;

WHEREAS, the regulation of oil and gas exploration and production activities, including hydraulic fracturing, has traditionally been the province of the states;

WHEREAS, the Act was never intended to grant to the federal government authority to regulate oil and gas drilling and production operations, such as "hydraulic fracturing," under the Underground Injection Control program;

WHEREAS, the member states of the IOGCC have adopted comprehensive laws and regulations to provide safe operations and to protect the nation's drinking water sources, and have trained personnel to effectively regulate oil and gas exploration and production;

WHEREAS, production of coal seam natural gas, natural gas from shale formations, and natural gas from tight conventional reservoirs is increasingly important to our domestic natural gas supply and will be even more important in the future;

WHEREAS, domestic production of natural gas will ensure that the United States continues on the path to energy independence;

WHEREAS, hydraulic fracturing plays a major role in the development of virtually all unconventional oil and gas resources and, in the absence of any evidence that such fracturing has damaged the environment, should not be limited;

WHEREAS, regulation of hydraulic fracturing as underground injection under the Act would impose significant administrative costs on the state and substantially increase the cost of drilling oil and gas wells with no resulting environmental benefits; and

WHEREAS, regulation of hydraulic fracturing as underground injection under the Act would increase energy costs to the consumer:

NOW, THEREFORE, BE IT RESOLVED that the Legislature of the state of Utah expresses support for maintaining the exemption of hydraulic fracturing in the Safe Drinking Water Act and urges the United States Congress to refrain from passing legislation that would remove the exemption for hydraulic fracturing.

BE IT FURTHER RESOLVED that a copy of this resolution be sent to the President of the United States, the Majority Leader of the United States Senate, the Speaker of the United States House of Representatives, and to the members of Utah's congressional delegation.

SENATE JOINT RESOLUTION NO. SJ0005

Hydraulic fracturing.

Sponsored by: Senator(s) Bebout, Anderson, J., Cooper, Hines, Martin and Vasey and Representative(s) Anderson, R., Cohee, Craft, Illoway, Lockhart, Lubnau, Meyer, Miller and Pedersen

A Bill

for

A JOINT RESOLUTION requesting Congress to preserve the exemption of hydraulic fracturing in the Safe Drinking Water Act and to not pass any future legislation which would remove the exemption.

WHEREAS, the United States Congress passed the Safe Drinking Water Act, 42 U.S.C § 300h (SDWA) to assure the protection of the nation's drinking water sources; and

WHEREAS, since the enactment of the SDWA, the United States Environmental Protection Agency (EPA) had never interpreted hydraulic fracturing as constituting "underground injection" within the SWDA; and

WHEREAS, the United States 11th Circuit Court of Appeals ruled contrary to argument of the EPA that hydraulic fracturing constituted "underground injection" under the SDWA. Legal Environmental Assistance Foundation v. United States Environmental Protection Agency, 118 F3d 1467 (11th Cir. 1997); and

WHEREAS, in 2004, the EPA published a final report summarizing a study to evaluate the potential threat to underground sources of drinking water (USDWs) from hydraulic fracturing of coalbed methane (CBM) production wells and concluded that "additional or further study is not warranted at this time…" and that "the injection of hydraulic fracturing fluids into CBM wells poses minimal threat to USDWs."; and

WHEREAS, the United States Congress, in the Energy Policy Act of 2005, explicitly exempted hydraulic fracturing from the provisions of the SDWA; and

WHEREAS, the Interstate Oil and Gas Compact Commission (IOGCC) conducted a survey of oil and gas producing states and found that there were no known cases of ground water contamination associated with hydraulic fracturing; and

WHEREAS, hydraulic fracturing is currently, and has been for decades, a common operation used in exploration and production by the oil and gas industry in all the member states of the IOGCC without groundwater damage; and

WHEREAS, approximately thirty-five thousand (35,000) wells are hydraulically fractured annually in the United States and nearly one million (1,000,000) wells have been hydraulically fractured in the United States since the technique's inception, with no known harm to groundwater; and

WHEREAS, the regulation of oil and gas exploration and production activities, including hydraulic fracturing, has traditionally been the province of the states; and

WHEREAS, the SWDA was never intended to grant to the federal government authority to regulate oil and gas drilling and production operations, such as "hydraulic fracturing", under the Underground Injection Control program; and

WHEREAS, the member states of the IOGCC have adopted comprehensive laws and regulations to provide for safe operations and to protect the nation's drinking water sources, and have trained personnel to effectively regulate oil and gas exploration and production; and

WHEREAS, production of coal seam natural gas, natural gas from shale formations and natural gas from tight conventional reservoirs is increasingly important to domestic natural gas supply and will be more important in the future; and

WHEREAS, domestic production of natural gas will ensure that the United States continues on the path to energy independence; and

WHEREAS, hydraulic fracturing plays a major role in the development of virtually all unconventional oil and gas resources and, thus, should not be limited in the absence of any evidence that hydraulic fracturing has damaged the environment; and

WHEREAS, regulation of hydraulic fracturing as underground injection under the SDWA would impose significant administrative costs on the state and substantially increase the cost of drilling oil and gas wells with no resulting environmental benefits; and

WHEREAS, regulation of hydraulic fracturing as underground injection under the SDWA would increase energy costs to the consumer.

NOW, THEREFORE, BE IT RESOLVED BY THE MEMBERS OF THE LEGISLATURE OF THE STATE OF WYOMING:

Section 1. That the Wyoming State Legislature hereby declares its support for maintaining the exemption of hydraulic fracturing from the provisions of the SDWA and urges the Congress of the United States not to pass legislation that would remove the exemption for hydraulic fracturing.

Section 2. That the Secretary of State of Wyoming transmit copies of this resolution to the President of the United States, to the President of the Senate and the Speaker of the House of Representatives of the United States Congress and to the Wyoming Congressional Delegation.

(END)

RESOLUTION 03.101
Urging Congress To Enact Legislation To Correctly Characterize Hydraulic Fracturing For Purposes Of The Safe Drinking Water Act

WHEREAS, the United States Congress passed the Safe Drinking Water Act (SDWA) to assure the protection of the nation's drinking water sources; and,

WHEREAS, there has now been final appeal of the 1997 case of Legal Environmental Assistance Foundation v. United States Environmental Protection Agency (EPA), 118 F3d 1467 (11th Cir. 1997), wherein the United States 11th Circuit Court of Appeals ruled contrary to argument of the U.S. EPA that hydraulic fracturing constituted "underground injection" under the SDWA; and,

WHEREAS, since the enactment of the SDWA, the EPA had never interpreted hydraulic fracturing as constituting "underground injection" within the SDWA; and,

WHEREAS, pursuant to the 11th Circuit opinion, the EPA required the Alabama Oil and Gas Board to change its regulation to maintain "primacy" over Class II underground injection activities, creating additional regulatory expense with no increased environmental protection; and,

WHEREAS, hydraulic fracturing is, and has been for decades, a common operation used in exploration and production by the oil and gas industry in all the member states of the Interstate Oil and Gas Compact Commission (IOGCC) without groundwater damage; and,

WHEREAS, the regulation of the oil and gas exploration and production activities, including hydraulic fracturing, has traditionally been within the province of the states; and,

WHEREAS, the SDWA never was intended to grant to the federal government authority to regulate oil and gas drilling and production operations such as "hydraulic fracturing" under the Underground Injection Control program; and,

WHEREAS, the member states of the IOGCC have comprehensive laws and regulations, and trained personnel to effectively regulate oil and gas exploration and production to provide for safe operations and to protect the nation's drinking water sources; and,

WHEREAS, hydraulic fracturing of coal seams plays a major role in the degasification process and should not be limited in the absence of any evidence that such fracturing has ever damaged the environment; and,

WHEREAS, the IOGCC has conducted a survey of oil and gas producing states which found that there have been no documented cases of ground water contamination associated with hydraulic fracturing; and, *Continued*

RESOLUTION 03.101
Page 2

WHEREAS, regulation of hydraulic fracturing as underground injection under the SDWA would impose significant administrative costs on the states and substantially increase the cost of drilling oil and gas wells with no resulting environmental benefits; and,

WHEREAS, legislation by Congress is needed to clarify that hydraulic fracturing should not be regulated as underground injection within the SDWA;

NOW, THEREFORE, BE IT RESOLVED, the IOGCC hereby declares its support for legislation providing hydraulic fracturing is not to be regulated as "underground injection" within the Safe Drinking Water Act.

RESOLUTION 01.121

Urging Congress To Enact Legislation To Correctly Characterize Hydraulic Fracturing For Purposes Of The Safe Drinking Water Act

WHEREAS, the United States Congress passed the Safe Drinking Water Act (SDWA) to assure the protection of the nation's drinking water sources; and,

WHEREAS, in 1997, in the case of Legal Environmental Assistance Foundation v. United States Environmental Protection Agency (EPA), 118 F3d 1467 (11th Cir. 1997), the United States 11th Circuit Court of Appeals ruled contrary to argument of the U.S. EPA that hydraulic fracturing constituted "underground injection" under the SDWA; and,

WHEREAS, since the enactment of the SDWA, the EPA had never interpreted hydraulic fracturing as constituting "underground injection" within the SDWA; and,

WHEREAS, pursuant to the 11th Circuit opinion, the EPA required the Alabama Oil and Gas Board to change its regulation to maintain "primacy" over Class II underground injection activities, creating additional regulatory expense with no increased environmental protection; and,

WHEREAS, hydraulic fracturing is, and has been for decades, a common operation used in exploration and production by the oil and gas industry in all the member states of the Interstate Oil and Gas Compact Commission (IOGCC) without groundwater damage; and,

WHEREAS, the regulation of the oil and gas exploration and production activities, including hydraulic fracturing, has traditionally been within the province of the states; and,

WHEREAS, the SDWA never was intended to grant to the federal government authority to regulate oil and gas drilling and production operations such as "hydraulic fracturing" under the Underground Injection Control program; and,

WHEREAS, the member states of the IOGCC have comprehensive laws and regulations, and trained personnel to effectively regulate oil and gas exploration and production to provide for safe operations and to protect the nation's drinking water sources; and,

WHEREAS, on Sept. 22, 2001, a coalbed methane explosion killed 13 miners in Alabama, reinforcing the fact that production of coalbed methane serves to degasify coal seams and reduces the risk of such explosions; and,

WHEREAS, hydraulic fracturing of coal seams plays a major role in the degasification process and should not be limited in the absence of any evidence that such fracturing has ever damaged the environment; and,

Continued

RESOLUTION 01.121

Page 2

WHEREAS, the Ground Water Protection Council (GWPC), a national organization of state and federal ground water regulators, conducted a survey of oil and gas producing states which found that there have been no documented cases of ground water contamination associated with hydraulic fracturing of coalbed methane wells; and,

WHEREAS, regulation of hydraulic fracturing as underground injection under the SDWA would impose significant administrative costs on the states and substantially increase the cost of drilling oil and gas wells with no resulting environmental benefits; and,

WHEREAS, legislation by Congress is needed to clarify that hydraulic fracturing should not be regulated as underground injection within the SDWA;

NOW, THEREFORE, BE IT RESOLVED, the IOGCC hereby declares its support for legislation providing hydraulic fracturing is not to be regulated as "underground injection" within the Safe Drinking Water Act.

RESOLUTION 99.603
URGING CONGRESS TO ENACT S.724 TO CORRECTLY CHARACTERIZE HYDRAULIC FRACTURING FOR PURPOSES OF THE SAFE DRINKING WATER ACT.

WHEREAS, the United States Congress passed the Safe Drinking Water Act in order to assure the protection of the nation's drinking water sources; and

WHEREAS, in 1997 in the case of Legal Environmental Assistance Foundation v. U.S. Environmental Protection Agency, 118F3d 1467 (11th Cir. 1997), the United States Eleventh Circuit Court of Appeals ruled contrary to argument of the U.S. EPA that hydraulic fracturing constitutes "underground injection" under the Safe Drinking Water Act (hereinafter referred to as "SDWA"); and

WHEREAS, since the enactment of the SDWA, the U.S. EPA had never interpreted that hydraulic fracturing constituted "underground injection" within the SDWA; and

WHEREAS, pursuant to an order of the Eleventh Circuit, the U.S. EPA has initiated proceedings to withdraw from the State of Alabama and the Alabama Oil and Gas Board "primacy" over Class II underground injection activities; and

WHEREAS, hydraulic fracturing is a common operation used by the oil and gas exploration and production industry in all the member states of the Interstate Oil and Gas Compact Commission; and

WHEREAS, the regulation of oil and gas exploration and production activities has traditionally been within the province of the states; and

WHEREAS, the SDWA never was intended to grant to the federal government authority to regulate oil and gas drilling and production operations such as "hydraulic fracturing" under the Underground Injection Control program; and

WHEREAS, the member states of the Interstate Oil and Gas Compact Commission have laws and regulations, and personnel to regulate effectively oil and gas exploration and production to provide for safe operations and to protect the nation's drinking water sources; and

WHEREAS, the Ground Water Protection Council, a national organization of state and federal ground water regulators, conducted a survey of oil and gas producing states, which found that there have been no documented cases of ground water contamination associated with hydraulic fracturing of coalbed methane wells; and

WHEREAS, regulation of hydraulic fracturing as underground injection under the SDWA would impose significant administrative costs on the states and substantially increase the cost of drilling oil and gas wells with no resulting environmental benefit; and

WHEREAS, legislation has been introduced in Congress to correct the error of the Eleventh Circuit by clarifying that hydraulic fracturing does not constitute underground injection within the SDWA.

NOW, THEREFORE, BE IT RESOLVED, the Interstate Oil and Gas Compact Commission hereby declares its support for S.724 or other legislation providing that hydraulic fracturing does not constitute "underground injection" within the Safe Drinking Water Act.

ACTION PLAN FOR RESOLUTION 99.603

URGING CONGRESS TO ENACT S.724 TO CORRECTLY CHARACTERIZE HYDRAULIC FRACTURING FOR PURPOSES OF THE SAFE DRINKING WATER ACT.

1). Send resolution to all IOGCC governors and official representatives.

2). Send the resolution to appropriate congressional committees.

3). Send the resolution to President Bill Clinton, Department of Energy Secretary Bill Richardson, EPA Administrator Carol Browner.

4). Send the resolution to oil and gas trade associations in each state.

5). Headquarters office to monitor progress on the legislation and keep states informed so they can contact their own Congressional Delegations.

RESOLUTION 95.901
Addressing The Duplication of Downhole Regulations

Whereas, the member states of the Interstate Oil and Gas Compact Commission (IOGCC) pursuant to the exercise of their respective state police powers, each has jurisdiction over the management of their respective natural resources including the extraction of oil and gas; and

Whereas, many of these states have enacted comprehensive legislation establishing oil conservation commissions including the delegation of jurisdiction and authority over all matters relating for the conservation of oil and gas; and

Whereas, each state oil and gas regulatory agency, pursuant to their statutory authority, routinely regulates development and production from oil and gas wells on federal, state, fee and Native American lands within the boundaries of each state in order to prevent waste of hydrocarbons, and to protect the correlative rights of all owners of those hydrocarbons; and to protect public health and safety and the environment; and

Whereas, these state agencies have longstanding established rules and regulations which include detailed requirements for technical hearings before qualified administrative hearing officers concerning matters of proper management of oil and gas operations within each state; and

Whereas, these state agencies have issued regulatory orders and decisions for creating operational rules and regulations governing all interest owners share of hydrocarbons within each identified oil/gas reservoir ("common source of supply") for the prevention of waste and the protection of correlative rights; and the protection of public health and safety and the environment; and

Whereas, pursuant to federal legislation, the United States Bureau of Land Management ("BLM") has been authorized to regulate all oil and gas operations conducted on a Federal or Indian oil and gas lease; and

Whereas, it is BLM policy to consult, cooperate, coordinate and enter into cooperative agreements with the federal and state agencies relating to oil and gas development and operations; and

Whereas, in the area of downhole responsibilities the BLM's various authorized officers have historically acquiesced with, concurred in and relied upon state agency regulatory orders as a basis for BLM-approval of oil and gas operations; and

Whereas, it is an unnecessary regulatory burden upon the oil and gas industry and an expensive duplication of regulatory effort by the BLM to require that orders and decisions issued by state agencies involving federal or Indian oil and gas leases be subject to a parallel process involving BLM approval or denial; and

Whereas, when different orders are issued there are obvious problems with operators trying to comply with differing orders from jurisdictional agencies covering the same issue; and

Whereas, it is in the best interests of all affected parties including the BLM that the BLM rely upon the regulatory conclusions and operational orders issued by qualified state agencies which makes possible the regulation of a pool (a single common source of supply) so that regardless of whether the leases are fee, federal, state or Indian, all owners will abide by the same set of operations regulations to prevent waste, to protect correlative rights and to protect public health and safety and the environment; and

Whereas, the IOGCC recognizes that surface land management jurisdictional issues are outside the scope of this resolution:

Now, Therefore, It is Hereby Resolved That: The Secretary of Interior's office require the BLM to develop an implementation plan through their BLM Performance Review to provide for the acceptance of the downhole regulatory conclusions and approvals rendered by state oil and gas conservation agencies related to the following items:

1. Pool rules including spacing exceptions and allowable allocations
2. Flare/no flare orders
3. Commingling orders
4. Groundwater Protection Measures
5. Enhanced Oil Recovery Determinations
6. Directional Drilling
7. Multiple Completions

September, 1995

pennsylvania
DEPARTMENT OF ENVIRONMENTAL PROTECTION
SECRETARY

April 6, 2011

Mr. Shawn M. Garvin
Regional Administrator
U.S. EPA Region III
1650 Arch Street
Philadelphia, PA 19103-2029

Dear Regional Administrator Garvin:

I write in response to your March 7, 2011, letter concerning wastewater issues related to drilling for natural gas in the Marcellus Shale formation. Rest assured that well before receiving your letter, the Pennsylvania Department of Environmental Protection (DEP) has been focusing on issues relating to natural gas drilling, and prioritizes protecting the environment and public health and safety above all else

We are guided by sound science and the facts. In that regard, we continue to agree with Steve Heare, head of EPA's Drinking Water Protection Division, when he stated, "I have no information that states aren't doing a good job already [regulating fracking]." Again, based on current data and facts here in Pennsylvania, any backtracking from that statement would be, in my opinion, unjustified. DEP has been and continues to aggressively refine its regulations, guidance, and policies addressing oil and gas drilling, associated waste management, treatment, and disposal, as well as increasing its field presence in the areas of inspections and enforcement.

Unfortunately, your letter, along with the recent New York Times articles, overlooks DEP's strong and ongoing efforts to protect the environment and public health. More specifically, the radionuclides and other pollutants of concern (barium and strontium) that were highlighted in your letter had all been previously identified by DEP and targeted in regulation, guidance, the National Pollutant Discharge Elimination System (NPDES) permitting process, instream sampling, and public drinking water sampling.

Also, your letter arrived the same day we announced the results of our in-stream water quality monitoring for radioactive material in seven of the commonwealth's rivers. All samples showed levels at or below the normal naturally occurring background levels of gross alpha and gross beta radiation. Those tests were conducted in November and December of 2010 at stations downstream of wastewater treatment plants that accept flowback and production water from Marcellus Shale drilling. These sampling stations were installed last fall specifically for the purpose of monitoring stream quality for potential impacts from unconventional gas drilling operations. The raw water river samples were collected above public water suppliers' intakes where the water receives further treatment.

The seven river testing stations are located at the Monongahela at Charleroi in Washington County; South Fork Ten Mile Creek in Greene County; Conemaugh in Indiana County; Allegheny at Kennerdell in Venango County; Beaver in Beaver County; Tioga in Tioga County; and the West Branch of the Susquehanna in Lycoming County. These stations were chosen because of their proximity to public water supply (PWS) intakes and at the time, were located downstream of facilities permitted to or proposing to discharge oil and gas wastewater. Future monitoring will include monthly sampling at the Monongahela; South Fork Ten Mile; Allegheny; and Beaver sites and every other month at the remaining three sites. Moreover, gross alpha and gross beta testing was added to a second water quality network station on the Monongahela, in March 2011. This site is further downstream in Allegheny County. All of the results will be frequently evaluated and available to the public via EPA's Modernized STORET database.

I want to bring to your attention certain other proactive steps that were pending prior to your letter. First, we have taken measures under Pennsylvania's regulations to have additional monitoring of finished water at 14 public water supplies with surface water intakes downstream from wastewater treatment facilities that accept Marcellus wastewater. On March 11, 2011, under Pennsylvania regulation 25 *PA Code* §109.302, we directed a letter to public water suppliers that have surface water intakes located downstream of one or more facilities that are accepting Marcellus wastewater to immediately conduct testing of radionuclides (i.e., radioactivity) and other parameters including Total Dissolved Solids (TDS), pH, alkalinity, chloride, sulfate and bromide. A copy of that letter and the list of recipients is enclosed.

Second, on March 18, 2011, under Pennsylvania regulation 25 *Pa Code* §92a.61(g), letters were sent to 25 Publicly Owned Treatment Works (POTWs) and Centralized Waste Treatment (CWT) facilities that currently accept this wastewater calling for immediate twice monthly effluent monitoring for radionuclides and other parameters including TDS, pH, alkalinity, chloride, sulfate, bromide, gross alpha, radium 226 & 228, and uranium. A copy of that letter and the list of recipients is enclosed.

In addition, over the past 3 years we have taken the actions necessary to protect the environment and public health without stifling the growth of the natural gas industry. During this time, we have consistently involved our EPA counterparts at Region III in decision-making through frequent communications, particularly our requests of interpretations concerning various federal regulations, as well as issues concerning the EPA pretreatment and underground injection control programs, both of which continue to be under federal jurisdiction in Pennsylvania. As per your invitation, we will consider participating in your efforts as the need arises.

In response to your specific requests for information and suggested actions:

You requested the identities and locations of all NPDES facilities in Pennsylvania accepting Marcellus Shale wastewater.

> We have shared the list of facilities treating wastewater from drilling activities and discharging pursuant to NPDES permits with your agency since we began tracking this wastewater. We provided the updated list on March 3, 2011. I have enclosed a copy of this list for your convenience.

You requested a list of permits that we plan to reopen and the parameters we plan to consider for reasonable potential analysis, and a schedule for completing the permit modifications.

> The monitoring data collected for permits of these types of facilities will be scrutinized prior to their renewal and where routine monitoring of the substances of concern is warranted, such requirements will be added to these permits. As stated above, those substances are: TDS, pH, alkalinity, chloride, sulfate, bromide, gross alpha, radium 226 & 228, and uranium. Where reasonable potential analysis indicates the need for effluent limitation, such limitations will be included in the permits.

Further, the radiological parameters gross alpha and beta are now collected at seven Water Quality Network (WQN) stations in areas most likely to be impacted by Marcellus Shale generated wastewater treatment and disposal and near drinking water intakes. An expansion in the number of WQN sites will be requested in the upcoming state budget and federal grant.

You requested a list of the community water systems that were required to conduct expedited monitoring, the sampling parameters and frequency and a schedule for initiating and completing these actions.

As stated above, the list of systems is enclosed. These systems were directed by letter on March 11, 2011, to test for radionuclides (i.e., gross alpha and gross beta radiation) and other parameters including TDS, pH, alkalinity, chloride, sulfate and bromide within 30 days of receipt of the letter.

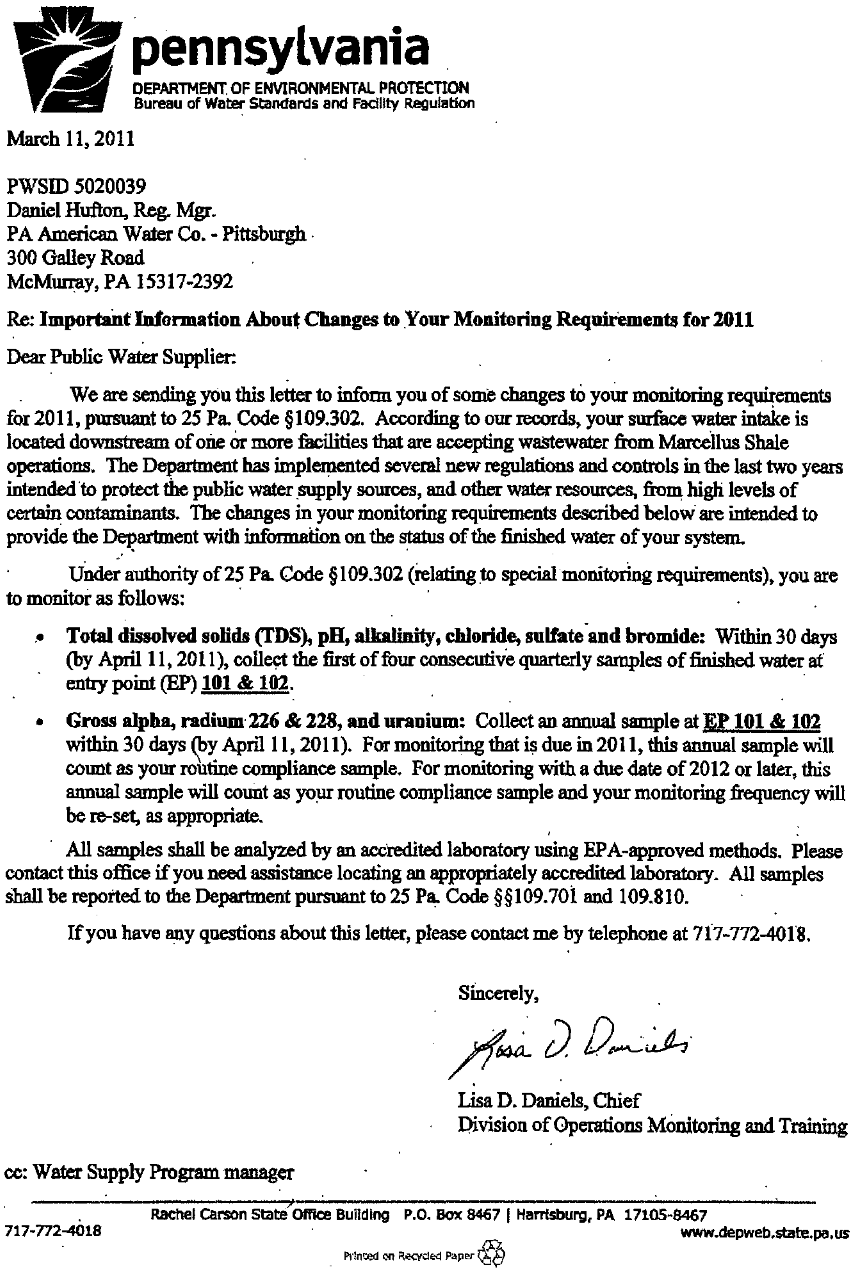
We have also planned for additional sampling this year for more than 40 surface drinking water intakes. Samples will be collected eight times over a course of several months for Marcellus Shale wastewater parameters including radionuclide. A revised 604(b) work plan is awaiting EPA approval. The plan includes two limited-term staff who will canvass the state sampling Marcellus Shale generated wastewater treatment discharges and receiving waters for radionuclide and other related substances. Once approved by EPA, a well conceived sampling plan designed to target critical areas where and when problems are likely to occur will be developed before staff take their first sample.

In closing, I want to thank you for your input and continued willingness to partner with DEP. In an effort to keep each other informed of our ongoing mutual efforts to protect the citizens of the commonwealth and the environment, I suggest that we meet quarterly and share our agency-wide priorities, environmental surveillance plans, and regulatory updates. My office will contact you shortly with a series of potential meeting dates. In the meantime, do not hesitate to contact me or my staff at Kelly Heffner, Acting Deputy Secretary, by e-mail at kheffner@state.pa.us or by telephone at 717.783.4693.

Sincerely,

Michael L. Krancer
Acting Secretary

Enclosures



pennsylvania
DEPARTMENT OF ENVIRONMENTAL PROTECTION
Bureau of Water Standards and Facility Regulation

March 11, 2011

PWSID 5020039
Daniel Hufton, Reg. Mgr.
PA American Water Co. - Pittsburgh
300 Galley Road
McMurray, PA 15317-2392

Re: **Important Information About Changes to Your Monitoring Requirements for 2011**

Dear Public Water Supplier:

We are sending you this letter to inform you of some changes to your monitoring requirements for 2011, pursuant to 25 Pa. Code §109.302. According to our records, your surface water intake is located downstream of one or more facilities that are accepting wastewater from Marcellus Shale operations. The Department has implemented several new regulations and controls in the last two years intended to protect the public water supply sources, and other water resources, from high levels of certain contaminants. The changes in your monitoring requirements described below are intended to provide the Department with information on the status of the finished water of your system.

Under authority of 25 Pa. Code §109.302 (relating to special monitoring requirements), you are to monitor as follows:

- **Total dissolved solids (TDS), pH, alkalinity, chloride, sulfate and bromide:** Within 30 days (by April 11, 2011), collect the first of four consecutive quarterly samples of finished water at entry point (EP) **101 & 102**.
- **Gross alpha, radium 226 & 228, and uranium:** Collect an annual sample at **EP 101 & 102** within 30 days (by April 11, 2011). For monitoring that is due in 2011, this annual sample will count as your routine compliance sample. For monitoring with a due date of 2012 or later, this annual sample will count as your routine compliance sample and your monitoring frequency will be re-set, as appropriate.

All samples shall be analyzed by an accredited laboratory using EPA-approved methods. Please contact this office if you need assistance locating an appropriately accredited laboratory. All samples shall be reported to the Department pursuant to 25 Pa. Code §§109.701 and 109.810.

If you have any questions about this letter, please contact me by telephone at 717-772-4018.

Sincerely,

Lisa D. Daniels

Lisa D. Daniels, Chief
Division of Operations Monitoring and Training

cc: Water Supply Program manager

Rachel Carson State Office Building P.O. Box 8467 | Harrisburg, PA 17105-8467
717-772-4018
www.depweb.state.pa.us

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List of PWSs that received the letter:

6610019	Aqua PA - Emlenton
5630039	Auth of Borough of Charleroi
5040012	Beaver Falls Mun Auth
5020006	Brackenridge Borough Water Dept
5030019	Buffalo Twp Mun Auth
5300005	Carmichaels Mun Water Auth
5040038	Midland Borough Mun Auth
5260014	Newell Mun Auth
6160001	PA American Water Co - Clarion
5020039	PA American Water Co - Pittsburgh
5630045	Tri County Jt Mun Auth
7220015	United Water
5020043	West View Borough Mun Auth
5020056	Wilkinsburg-Penn Jt Water Auth

pennsylvania
DEPARTMENT OF ENVIRONMENTAL PROTECTION
BUREAU OF WATER STANDARDS AND FACILITY REGULATION

March 18, 2011

Mr. James Cochran
Project 5/Timberline Treatment Facility
P.O. Box 269
Franklin, PA 16323-0269

Re: **Request for Information** – Permit ID: PA0222011
Big Sandy Oil Co.

Dear Mr. Cochran:

According to our records, your facility is accepting wastewater from Marcellus Shale operations. The Department of Environmental Protection (DEP) implemented several new regulations and controls in the last two years intended to protect public water supply sources and other water resources from high levels of certain contaminants. The changes in the monitoring requirements described below are intended to provide DEP with information on the status of the effluent water quality from your facility.

If your NPDES permit has already been modified to include monitoring for these parameters, then you are already compliant. If your permit has not yet been updated to reflect these new testing requirements, DEP requests that you voluntarily begin doing so within 30 days of receipt of this letter, as follows:

- TDS, pH, alkalinity, chloride, sulfate and bromide: collect twice monthly samples, on days that you are receiving the wastewater from natural gas drilling activities, at outfall 001.
- Gross Alpha, Radium 226 & 228, and Uranium: Collect twice monthly samples, on days that you are receiving the wastewater from natural gas drilling activities, at outfall 001.
- Samples should be collected as composites of minimum 8-hour duration, except pH, which should be collected as a grab.
- All samples should be analyzed by an accredited laboratory using EPA-approved methods. Please contact this office if you need assistance locating an appropriately accredited laboratory.
- Under authority of 25 *Pa. Code* § 92a.61(g), all sample results shall be reported to DEP within 30 days of obtaining the results.

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717.787.8184 | 717.772.5156 Printed on Recycled Paper www.depweb.state.pa.us

We request that any sample results be reported to DEP as soon as possible. If you have any questions about this letter, please contact me by e-mail at rfurlan@state.pa.us or by telephone at 717.787.8184.

Sincerely,

Ronald C. Furlan PE, Manager
Division of Planning and Permits

cc: Water Quality Program Manager
File

Permit No.	Permittee	Fname	Lname	Address 1	Address 2	City	State	Zip	Outfall	Municipality	County
PA0008451	Sunbury Generation LP	Mark	Crawford	P.O. Box 517		Shamokin Dam	PA	17876-517	IMP 130	Monroe	Snyder
PA0020346	Punxsutawney Borough Municipal Authority, Jefferson County			301 E. Mahoning Street		Punxsutawney	PA	15767	001	Punxsutawney	Jefferson
PA0023213	Ridgeway Borough, Elk County	Paul	McCurdy	P.O. Box 149		Ridgway	PA	15853-0149	001	Ridgway	Elk
PA0026034	Johnstown Redevelopment Authority	Frank	D'Ettore	Public Safety Bldg, 4th Floor		Johnstown	PA	15901	001	West Taylor	Cambria
PA0026255	Allegheny Valley Joint Sewer Authority	Richard	Chiavetta	2400 Freeport Road	P.O. Box 158	Cheswick	PA	15024-0158	001	Harmar	Allegheny
PA0026310	Clearfield Municipal Authority, Clearfield County	Jeffery	Williams	107 E. Market Street		Clearfield	PA	16830	001	Lawrence	Clearfield
PA0026824	Clairton City Municipal Authority, Allegheny County	Patrick	Canavan	1 N. State Street		Clairton	PA	15025-2172	001	Clairton (D)	Allegheny
PA0026913	McKeesport City Municipal Authority, Allegheny County	Joseph	Rost	100 Atlantic Avenue		McKeesport	PA	15132-3807	001	McKeesport	Allegheny
PA0027022	Altoona Water Authority	Mark	Perry	900 Chestnut Avenue		Altoona	PA	16601	001	Altoona	Blair
PA0027057	Williamsport City Sanitary Authority, Lycoming County	Walter	Nicholson	253 W 4th Street		Williamsport	PA	17701-6113	001	Williamsport	Lycoming
PA0027511	New Castle City Sanitation Authority, Lawrence County	Joseph	McIlvenny	110 E. Washington Street	P.O. Box 1404	New Castle	PA	16101-3815	001	New Castle	Lawrence
PA0027626	Kiski Valley Water Pollution Control Authority	Robert	Kossak	1361 School Road		Leechburg	PA	15656-4904	001	Allegheny	Westmoreland
PA0028207	Reynoldsville Borough Authority, Jefferson County	Gary	Drayer	400 N. 5th Street		Reynoldsville	PA	15851-1342	001	Reynoldsville	Jefferson
PA0028428	Brockway Area Sewage Authority, Jefferson County	Susan	Freemer	70 Industrial Park Drive		Brockway	PA	15824-1240	001	Brockway	Jefferson
PA0046426	Franklin Township Sewer Authority, Greene County	George	Scott	P.O. Box 752		Waynesburg	PA	15370-752	001	Franklin	Greene
PA0091472	Tunnelton Liquids Co.	Bruce	Bufalini	P.O. Box 667	9 Domenica Circle	Clarion	PA	16214-0667	001	Conemaugh	Indiana
PA0095273	Pennsylvania Brine Treatment			P.O. Box 296	Belts Mills Road	Joesphine	PA	15750	001	Burrell	Indiana
PA0095443	Hart Resouce Technologies, Inc.	Rebecca	Snyder	P.O. Box 232		Creekside	PA	15732-0232	401 & 501	Washington	Indiana
PA0101508	Franklin Brine Treatment Corp.	Elton	DeLong	5148 US 322		Franklin	PA	16323-7944	001	Cranberry	Venango
PA0101656	Dominion Transportation, Inc.	Russ	Gregory	P.O. Box 97	State Routes 410 & 119	Luthersburg	PA	15848-0097	101, 201	Henderson	Jefferson
PA0102784	Waste Treatmetn Corp.	Michael	Arnold	P.O. Box1561		Warren	PA	16365-6561	001	Warren	Warren
PA0103446	Veolia ES Greentree Landfill, LLC	Donald	Henrichs	635 Toby Road		Kersey	PA	15846-1033	001	Fox	Elk
PA0105295	Minard Run Oil Co.	W.	Bulmer	609 South Avenue	Box 18	Bradford	PA	16701-3977	002	Lafayette	McKean
PA0112623	JJ Bucher Producing Corp.	Gregory	Maxon	2568 Bells Run Road		Shinglehouse	PA	16748-3030	001	Sharon	Potter
PA0222011	Big Sandy Oil Co.	James	Cochran	P.O. Box 269		Franklin	PA	16323-0269	001	Cranberry	Venango

Oil and Gas Wastewater Facility List

Please be advised that the below list isn't a complete list and can be modified at any time. It doesn't include all treatment facilities particularly treatment facilities that don't require the issuance of a Clean Streams Law and/or NPDES permit. Other treatment and disposal facilities exist, for example: injection disposal wells approved by the EPA Region III injection control program, as well as other waste processing and disposal facilities permits approved by Pa DEP Bureau's of Waste Management, Oil and Gas or Mineral Resource Management.

Facility Abbreviations:

CWT - Centralized Waste Treatment
POTW - Publicly Owned Treatment Works

Other Abbreviations:

TDS - Total Dissolved Solids
WQM - Water Quality Management

SWRO

NAME	Permit Number	Receiving Stream	Watershed	Design Flow (MGD)	Operating Flow (MGD)	Proposed or Average Oil & Gas Wastewater Flow (MGD)	County	Latitude	Longitude	Municipality	TYPE	Status / NOTES
Shallenberger Construction - Rankin Run Facility	PA[illegible]	Rankin Run	Monongahela River Watershed	0.125	N/A	0.125	Fayette	39.9534	-79.[illegible]	Dunbar Township	Proposed CWT	Proposed CWT, WQM Part I permit is issued and the WQM Part II permit application has been submitted. No proposed TDS treatment.
Mon Valley Brine	PA[illegible]	Monongahela River	Monongahela River Watershed	0.2	N/A	0.2	Washington	40.1881	-79.[illegible]	Donora Borough	Proposed CWT	Proposed CWT, WQM Part I draft permit application is under technical review. No Proposed TDS treatment.
Green Earth Wastewater	PA[illegible]	Dunkard Creek	Monongahela River Watershed	0.25	N/A	0.25	Greene	39.7430	-80.[illegible]	Perry Township	Proposed CWT	Proposed CWT, WQM Part I draft permit application is under technical review. No Proposed TDS treatment.
Shallenberger Construction	PA[illegible]	Youghiogheny River	Monongahela River Watershed	1.0	N/A	1.0	Fayette	40.0453	-79.[illegible]	Upper Tyrone Township	Proposed CWT	Proposed CWT, WQM Part I Permit application has been submitted. No proposed TDS treatment.
Somerset Regional Water Resources, LLC	PA[illegible]	East Branch Coxes Creek	Monongahela River Watershed	1.0	N/A	1.0	Somerset	40 00 27.6	79 04 17.4	Somerset Township	Proposed CWT	Proposed CWT, WQM Part I & Part II permits issued, however, WQM Part I Permit is in the amendment process. Proposing to treat to 500 mg/L TDS.
Penn Woods Enterprises, LLC	PA[illegible]	Casselman River	Monongahela River Watershed	0.5	N/A	0.5	Somerset	[illegible] 49 40	79 02 27	Summit Township	Proposed CWT	Proposed CWT, WQM Part I draft permit application is under technical review. No proposed TDS treatment.
Frontier Energy Services	PA0254207	Yellow Creek	Allegheny River Watershed	0.9	N/A	0.8	Indiana	40 33 29	79 09 27	White Township	Proposed CWT	Proposed CWT, WQM Part I Permit application has been submitted. No proposed TDS treatment.
Avonmore Coalbed Methane Water Treatment Facility	PA[illegible]	Kiskiminetas River	Allegheny River	0.21	N/A	0.21	Indiana	40 37 22	79 32 19	Blacklick Township	Proposed CWT	Proposed CWT (Coal Bed Methane), WQM Part I Permit application is under technical review. No proposed TDS treatment.
Guttman Coalbed Methane WTP	PA0253677	Monongahela River	Monongahela River Watershed	0.6	N/A	0.6	Washington	40.139	-79.872	Speers Borough	Proposed CWT	Proposed CWT (Coal Bed Methane) facility. WQM Part I Permit application has been submitted. No proposed TDS Treatment.
Reserved Environmental Services, LLC	PA[illegible]	Sewickley Creek and Belson Run	Monongahela River Watershed	ZLD - Zero Liquid Discharge	ZLD	ZLD	Westmoreland	40 12 16	79 36 20	Hempfield	Existing CWT	Existing CWT recycles oil and gas wastewater with zero liquid discharge. WQM Part I Permit application is submitted to expand recycling operations.
Shallenberger Construction – Renco Facility	PA[illegible]	Monongahela River	Monongahela River Watershed	0.6	ZLD	0.5	Fayette	39.8744	-79.9477	German Township	Existing CWT	Existing CWT currently recycles oil and gas wastewater with zero liquid discharge. WQM Part II Permit application is under technical review to expand recycling operations.
PA Brine [illegible]	PA[illegible]	Blacklick Creek	Allegheny River Watershed	0.12	0.12	0.12	Indiana	40.4787	-79.1796	Burrell Township	Existing CWT	Existing CWT, No TDS treatment.
Hart Resource	PA[illegible]	McKee Run	Allegheny River Watershed	0.045	0.045	0.045	Indiana	40.675	-79.[illegible]	Washington Township	Existing CWT	Existing CWT, No TDS treatment.
Tunnelton Liquids	PA[illegible]	Conemaugh River	Allegheny River Watershed	1.0	1.0	1.0	Indiana	40.4[illegible]	-79.[illegible]	Conemaugh Twp	Existing CWT	Existing CWT, No TDS treatment.
[illegible]	PA[illegible]	Jacobs Creek	Monongahela River Watershed	0.6	0.6	0.6	Westmoreland	40 06 21.45	79 34 1.32	East Huntingdon	Existing CWT	Existing CWT (Coal Bed Methane) facility. No TDS Treatment.
[illegible]	PA[illegible]	Blacklick Creek	Allegheny River	0.5	0.5	0.5	Indiana	40.[illegible]	-79.2932	Blacklick Township	Existing CWT	Existing CWT (Coal Bed Methane) facility. No TDS Treatment.
CNX Gas Co LLC	PA[illegible]	[illegible] Run	Monongahela River Watershed	0.007	0.007	0.007	Greene	39.[illegible]	-80.324	Jackson Township	Existing CWT	Existing CWT (Coal Bed Methane) facility. No TDS Treatment.
CB Energy	PA[illegible]	Conemaugh River	Allegheny River	0.2	0.2	0.2	Westmoreland	40.[illegible]	-79.1151	St. Clair Township	Existing CWT	Existing CWT (Coal Bed Methane) facility. No TDS Treatment.
CNX Gas Co LLC	PA[illegible]	Pennsylvania Fork Fish Creek	Monongahela River Watershed	0.0113	0.0111	0.0111	Greene	39.7707	-80.[illegible]	Freeport Township	Existing CWT	Existing CWT (Coal Bed Methane) facility. No TDS Treatment.
[illegible] Treatment Facility	PA[illegible]	[illegible] Creek	Allegheny River	0.2	0.2	0.2	Cambria	40.5554	-79.5459	Allegheny Township	Existing CWT	Existing CWT (Coal Bed Methane) facility. No TDS Treatment.
CNX Gas Co LLC	PA[illegible]	Crooked Creek	Allegheny River	0.15	0.15	0.15	Armstrong	40.6371	-79.3542	Southbend Township	Existing CWT	Existing CWT (Coal Bed Methane) facility. No TDS Treatment.
CNX Gas Co LLC	PA[illegible]	Blacklegs Creek	Allegheny River	0.095	0.095	0.095	Indiana	40.5514	-79.3945	Young Township	Existing CWT	Existing CWT (Coal Bed Methane) facility. No TDS Treatment.

CNX Gas Co LLC	PA0253057	Youghiogheny River	Monongahela River Watershed	0.06	0.06	0.06	Westmoreland	40.2577	-79.7907	Sewickley Township	Existing CWT	Existing CWT (Coal Bed Methane) facility. No TDS Treatment.
CNX Gas Co LLC	PA0253049	Crawford Run / Youghiogheny River	Monongahela River Watershed	0.06	0.06	0.06	Westmoreland	40.2979	-79.7068	Huntingdon Township	Existing CWT	Existing CWT (Coal Bed Methane) facility. No TDS Treatment.
[illegible] Treatment Facility	PA0219312	Sewickley Creek	Monongahela River Watershed	0.2	0.2	0.2	Westmoreland	40.2183	-79.516	Mt. Pleasant Township	Existing CWT	Existing CWT (Coal Bed Methane) facility. No TDS Treatment.
Castle Oil & Gas Company	PA0206075	Blacklick Creek	Allegheny River	0.46	0.46	0.46	Indiana	40.4791	-79.2287	Burrell Township	Existing CWT	Existing CWT (Coal Bed Methane) facility. No TDS Treatment.
Belden and Blake	PA0218888	Conemaugh River	Allegheny River	0.6	0.6	0.6	Westmoreland	40.4982	-79.309	Derry Township	Existing CWT	Existing CWT (Coal Bed Methane) facility. No TDS Treatment.
CB Energy Inc	PA0219452	Crabtree Creek	Allegheny River	0.2	0.2	0.2	Westmoreland	40.3692	-79.442	Salem Township	Existing CWT	Existing CWT (Coal Bed Methane) facility. No TDS Treatment.
Belden & Blake OG Facility	PA0217778	Youghiogheny River	Monongahela River Watershed	0.6	0.6	0.6	Fayette	40.0224	-79.593	Dunbar Township	Existing CWT	Existing CWT (Coal Bed Methane) facility. No TDS Treatment.
CNX Gas CO LLC	PA0253041	Dry Run	Monongahela River Watershed	0.1	0.1	0.1	Washington	40.186	-79.917	City of Monongahela	Existing CWT	Existing CWT (Coal Bed Methane) facility. No TDS Treatment.
CNX Gas Company LLC Pigeon Creek	PA0253058	Pigeon Creek	Monongahela River Watershed	0.2	0.2	0.2	Washington	40.138	-79.887	Fallowfield Township	Existing CWT	Existing CWT (Coal Bed Methane) facility. No TDS Treatment.
CNX Gas Company LLC OG Facility	PA0253251	Monongahela River	Monongahela River Watershed	0.6	0.6	0.6	Washington	40.091	-79.881	Elco Borough	Existing CWT	Existing CWT (Coal Bed Methane) facility. No TDS Treatment.
Clairton Municipal Authority	PA0026824	Peters Creek	Monongahela River Watershed	6.0	3.434	0.085	Allegheny	40 18 13	79 52 57	Clairton	Existing POTW	Existing POTW. No TDS treatment.
Municipal Authority City of McKeesport	PA0026913	Monongahela River	Monongahela River Watershed	11.5	10.229	0.102	Allegheny	40 21 11	79 52 15	City of McKeesport	Existing POTW	Existing POTW. No TDS treatment.
Allegheny Valley Joint Sanitary Auth.	PA0026255	Allegheny River	Allegheny River Watershed	3.5	3.645	0.025	Allegheny	40 31 49	79 50 53	Harmar Township	Existing POTW	Existing POTW. No TDS treatment.
Johnstown Redevelopment Authority - Dornick Point STP	PA0026034	Conemaugh River	Allegheny River Watershed	12.0	7.842	0.076	Cambria	40 21 52	78 57 13	West Taylor Twp.	Existing POTW	Existing POTW. No TDS treatment.
Kiski Valley WPCA/McCutcheon Enterprises (CWT)	PA0027626	Kiskiminetas River	Allegheny River Watershed	7	4.0	0.03	Westmoreland	40 38 34	79 35 05	Allegheny Township	Existing POTW receiving indirect discharge from existing CWT	Existing POTW/CWT. No TDS Treatment.
Franklin Township Sewer Authority/Tri-County Waters (CWT)	PA0046426	South Fork Tenmile Creek	Monongahela River Watershed	1.25	1.088	0.05	Greene	39 54 08	80 08 01	Franklin Township	Existing POTW receiving indirect discharge from existing CWT	Existing POTW/CWT. No TDS Treatment.

NWRO

NAME	Permit Number	Receiving Stream	Watershed	Design Flow (MGD)	Operating Flow (MGD)	Proposed or Average Oil & Gas Wastewater Flow (MGD)	County	Latitude	Longitude	Municipality	Type	Status / Notes
Titusville Oil and Gas Associates, Inc. - Hiram Hadley Lease	Approval No. 6196001 for coverage under GP PAG316004	Allegheny River	Allegheny	0.002	NA	0.002	Venango	41°27' 22.4"	79°36' 39.2"	Cornplanter Twp	Proposed Stripper	Proposed Stripper Well. WQM Part I Permit issued. No application for WQM Part II Permit and no proposed TDS treatment.
Vesco LLC	Approval No. 1008001 for coverage under GP PAG216004	Little Connoquenessing Creek	Ohio	0.0039	NA	0.0039	Butler	40° 48' 41"	80° 02' 04"	Connoquenessing Twp.	Proposed Stripper	Proposed CWT (Stripper Well). WQM Part I and Part II Permit issued. Facility under construction and no proposed TDS treatment.
ARMAC Resources	Approval No. 6298001 for coverage under GP PAG216004	Brokenstraw Creek	Allegheny	0.001	0.001	0.001	Warren	41°51' 4.2"	79°18' 8.8"	Brokenstraw Twp	Existing Stripper	Existing Stripper Well. No TDS treatment.
PA Brine Treatment - Rouseville Facility	PA0263516	Oil Creek	Allegheny	0.05	NA	0.05	Venango	41°28' 37"	79°41' 39"	Cornplanter Twp	Proposed CWT	Proposed CWT. WQM Part I Permit issued. No application for WQM Part II Permit. Proposing to treat to 500 mg/L.
Minard Run Oil Company	PA0102695	Lewis Run	Allegheny	0.004	0.004	0.004	McKean	41°50' 41.9"	78°41' 34.4"	Lafayette Twp	Existing CWT	Existing facility. No TDS treatment.
Big Sandy Oil Company	PA0222011	Allegheny River	Allegheny	0.085	0.084	0.084	Venango	41°24' 17.7"	79°44' 11.2"	Cranberry Twp	Existing CWT	Existing facility. No TDS treatment.
Waste Treatment Corporation	PA0102784	Allegheny River	Allegheny	0.215	0.199	0.199	Warren	41°50' 15"	79°08' 41"	Warren City	Existing CWT	Existing CWT. No TDS treatment.
PA Brine Treatment - Franklin Facility	PA0101508	Allegheny River	Allegheny	0.324	0.144	0.144	Venango	41°22' 39"	79°49' 01"	Cranberry Twp	Existing CWT	Existing CWT. No TDS treatment.
Dannic Energy Corp - Div V	PA0101656	Sandy Creek	Allegheny	0.0108	0.0077	0.0077	Jefferson	40°59' 14.8"	78°59' 36.6"	Henderson Twp	Existing CWT	Existing CWT. No TDS treatment.
Veolia ES Greentree Landfill LLC	PA0103446	Little Toby Creek	Allegheny	0.25	0.25	0.0495	Elk	41°17' 57"	78°36' 57"	Fox Twp	Existing CWT	Existing CWT. No TDS treatment.
Ridgway Borough	PA0023213	Clarion River	Allegheny	2.2	1.4	0.02	Elk	41°25' 16"	78°43' 09"	Ridgway Borough	Existing POTW	Existing POTW. No TDS treatment.
Reynoldsville Sew	PA0028207	Sandy Lick Creek	Allegheny	0.6	0.5	0.011	Jefferson	41.05.41	78.53.49	Reynoldsville Borough	Existing POTW	Existing POTW. No TDS treatment.
Punxsutawney Borough/Dannic Energy	PA0020346	Mahoning Creek	Allegheny	2.2	1.5	0.02	Jefferson	40°56' 25"	79°00' 6.6"	Punxsutawney Borough	Existing POTW receiving indirect discharge from existing CWT	Existing POTW/CWT. No TDS treatment.
Brockway Area Sewage Authority/Dannic Energy	PA0028428	Toby Creek	Allegheny	1.3	0.8	0.014	Jefferson	41°15' 11"	78°47' 59"	Brockway Borough	Existing POTW receiving indirect discharge from existing CWT	Existing POTW/CWT. No TDS treatment.
New Castle City / Advanced Waste Services	PA0027511	Mahoning River	Ohio	17	8.4	0.55	Lawrence	40°58' 09"	80°22' 22.1"	New Castle City	Existing POTW receiving indirect discharge from existing CWT	Existing POTW/CWT. No TDS treatment.

NCRO

NAME	Permit Number	Receiving Stream	Watershed	Design Flow (MGD)	Operating Flow (MGD)	Proposed or Average Oil & Gas Wastewater Flow (MGD)	County	Latitude	Longitude	Municipality	TYPE	Status / NOTES
Keystone Clearwater Solutions, LLC	PA0233650	West Branch Susquehanna River	WB Susquehanna	0.504	N/A	0.504	Clinton	41° 05' 57.74"	77° 20' 2.82"	Pine Creek Township	Proposed CWT	Proposed CWT, WQM Part I draft permit is out for comment. Proposing to treat to 500 mg/L TDS.
Keystone Clearwater Solutions, LLC	PA0233651	Moshannon Creek	WB Susquehanna	0.504	N/A	0.504	Centre	40° 57' 58"	78° 03' 48"	Rush Township	Proposed CWT	Proposed CWT, WQM Part I draft permit is out for comment. Proposing to treat to 500 mg/L TDS.
TerrAqua Resource Management	PA0233660	West Branch Susquehanna River	WB Susquehanna	0.4	N/A	0.4	Lycoming	41° 14' 43"	76° 59' 09"	City of Williamsport	Proposed CWT	Proposed CWT, WQM Part I Permit has been issued. WQM Part II application not submitted. Proposing to treat to 500 mg/L TDS.
Somerset Regional Water Resources	PA0228001	NB Susquehanna	NB Susquehanna	0.5	N/A	0.5	Bradford	41° 48' 4.21"	76° 11' 31.65"	Tuscarora Township	Proposed CWT	Proposed CWT, WQM Part I Permit has been issued. WQM Part II application not submitted. Proposing to treat to 500 mg/L TDS.
Sunbury Generation	PA0008451	Susquehanna River	Lower Susquehanna	3.7	1.7	0.08	Snyder	40° 49' 43"	76° 50' 08"	Monroe Township	Existing CWT	Existing facility. No TDS treatment.
JJ Bucher	PA0112623	Oswayo Creek	Allegheny River	0.07	0.0138	0.02	Potter	41° 59' 32"	78° 12' 11"	Shinglehouse Borough	Existing CWT	Existing facility. No TDS treatment.
Clearfield Municipal Authority	PA0026310	West Branch Susquehanna River	WB Susquehanna	4.8	2.65	0.01	Clearfield	41° 01' 31"	78° 24' 02"	Clearfield Borough	Existing POTW	Existing POTW. No TDS treatment.
Williamsport Sanitary Authority / Eureka Resources	PA0027057	West Branch Susquehanna River	WB Susquehanna	8.4	5.89	0.12	Lycoming	41° 14' 16"	76° 58' 34"	City of Williamsport	Existing POTW receiving indirect discharge from existing CWT	Both facilities operating. CWT treats to 500 mg/L TDS.

NERO

NAME	Permit Number	Receiving Stream	Watershed	Design Flow (MGD)	Operating Flow (MGD)	Proposed or Average Oil & Gas Wastewater Flow (MGD)	County	Latitude	Longitude	Municipality	TYPE	Status / NOTES
Wyoming Somerset Regional Water Resources LLC	Appln. No. PA0065293	Meshoppen Creek	NB Susquehanna	0.38	N/A	0.38	Wyoming	41°37'39.4"	75°56'36.4"	Lemon Township	Proposed CWT	Proposed CWT, WQM Part I draft permit is under technical review. Proposing to treat to 500 mg/L TDS.

SCRO

NAME	Permit Number	Receiving Stream	Watershed	Design Flow (MGD)	Operating Flow (MGD)	Proposed or Average Oil & Gas Wastewater Flow (MGD)	County	Latitude	Longitude	Municipality	TYPE	Status / NOTES
Altoona West STP	PA0027022	Beaver Dam Branch Juniata River	Juniata River	16.2	5.6	0.01	Blair	40 27' 15.5"	78 25' 35.3"	Allegheny Twp.	Existing POTW	Existing POTW. No TDS treatment

Facilities Operating Under The Residual Waste General Permit

NAME	Permit Number	Receiving Stream	Watershed	Design Flow (MGD)	Operating Flow (MGD)	Proposed or Average Oil & Gas Wastewater Flow (MGD)	County	Latitude	Longitude	Municipality	TYPE	Status / NOTES
TerrAqua Resource Management LLC	WMGR121	Zero Liquid Discharge	West Branch Susquehanna	0.4	0.4	0.4	Lycoming	41.14.43	76.59.9	Williamsport	Existing CWT	Existing CWT (residual waste processing facility). Recycles oil and gas wastewater with zero liquid discharge.
Reserved Environmental Services LLC	WMGR123SW001	Zero Liquid Discharge	Monongahela River	1.0	0.7	0.85	Westmoreland	40.11.29	79.34.38	Hempfield Twp	Existing CWT	Existing CWT (residual waste processing facility). Recycles oil and gas wastewater with zero liquid discharge.
Eureka Resources, LLC	WMGR119	Zero Liquid Discharge	West Branch Susquehanna	0.8	0.1	0.8	Lycoming	41°14'13.69"	77° 00' 30.19"	City of Williamsport	Existing CWT	Existing CWT (residual waste processing facility). Recycles oil and gas wastewater with zero liquid discharge.
Hydro Recovery, LP	WMGR123	Zero Liquid Discharge	Tioga River	0.61	N/A	0.3	Tioga	41°40'18"	77° 04' 21"	Blossburg	Proposed CWT	Proposed CWT (residual waste processing facility). Proposes to recycle oil and gas wastewater with zero liquid discharge. Facility is under construction.

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April 7, 2011

The Honorable James Inhofe

State Regulation of the Oil and Gas Industry

Dear Senator Inhofe:

Thank you for this opportunity to briefly comment on the regulation of the oil and gas industry by our individual states.

Every one of our 33 states, producing oil and natural gas, regulates the activity within their borders. Each state's regulatory body operates under rules and regulations that have been duly promulgated within their state and have missions and goals to safely explore and produce the natural resources of the state while protecting the environment. Our state agencies have managers and staff members who are professionals in the fields of the earth sciences and engineering and have decades of experience.

States regulate the oil and gas industry within their borders because of three basic facts:

1. Minerals are privately owned by individual state citizens
2. Geology varies from state-to-state, within each state, and from one sedimentary basin to another
3. Climatic conditions vary from state-to-state

These basic facts are expanded as follows:

Private Ownership

- The United States is the only country in the world where minerals are owned by private citizens.
- The leasing and production of these minerals benefits not only the individual owners but school and road districts within counties and states.
- Since both the surface and mineral estates are privately owned, each state has statutes that allow regulatory agency personnel to physically inspect wells and facilities and not be in trespass against the private owners.

Geology

- Thousands of different rock formations are encountered across the continent of North America, not one is ubiquitous, and many are to be found only in a particular state or group of states.
- There are over 50 oil and gas basins, within the lower-48 states, and each unique basin requires individual state expertise and knowledge to understand geologic aspects.
- The rocks in the stratigraphic columns of oil and gas basins are highly variable with respect to their physical properties and state knowledge of these properties impacts rules for safe drilling and production practices.
- The fluids contained within the many formations are highly variable and knowledge of safe and successful drilling and completion methods is imperative.
- Pressure regimes within the formations range from under-pressured to normal to over-pressured and individual well design and permitting is best administered by experienced and knowledgeable state personnel.

Climatic Conditions

- Each state has unique climate and weather conditions that affect oil and gas operations. Rules can be, and are, tailored to local or regional conditions within any given state.
- The permitting and regulation of an individual well and its location requires local knowledge and experience.

Given the variable nature of these aspects, we may conclude that, "One size doesn't fit all!" State personnel are involved in the regulation of wells from cradle-to-grave. Many times, they are involved in the design of wells prior to permitting and then are always involved in the drilling, completion, production, final abandonment, and surface restoration of each well.

The people who regulate this industry live in their respective states and have a vested interest in safe and successful operations. The expertise and experience levels of state regulators are exceptional and can not be duplicated. The regulations they enforce are tailored to the unique geology, reservoirs, climate and operating conditions of their state. The regulation of oil and gas must remain within each state.

Respectfully,
William H. Sydow
Director
Nebraska Oil and Gas Conservation Commission

PITTSBURGH
TRIBUNE-REVIEW

Drilling opponent to leave Pitt post

By Luis Fabregas
PITTSBURGH TRIBUNE-REVIEW
Sunday, April 10, 2011

A University of Pittsburgh researcher who is a vocal critic of Marcellus shale drilling said Saturday he is leaving his post because the university won't allow him to speak publicly about environmental issues, not because of online criticism of his work.

Conrad "Dan" Volz, director of the Center for Healthy Environments and Communities at Pitt's Graduate School of Public Health, said he was not fired or under pressure to resign, but finds he has a calling for advocating for public health.

"There is a basic philosophical difference," said Volz, 57, of West Deer. "What the university is saying is that they don't want people to talk about things. They want to do scholarly research and publish it in journals and have it go out into the world."

Dr. Donald S. Burke, dean of the school, could not be reached for comment. Pitt spokeswoman Allison Schlesinger said she was unable to comment without his approval.

Volz claims drinking water is being contaminated by Marcellus shale drilling. He authored a report in March that showed a high concentration of bromide in Marcellus wastewater at the Josephine brine treatment facility, located in Indiana County, in the Allegheny River watershed. Bromide is a natural compound found in seawater that can form chemicals linked to cancer in laboratory animals when mixed with chlorine used to treat drinking water, Volz said.

"It is now starting to affect drinking water in the Pittsburgh area because the bromide levels in the rivers are so high," Volz said. He and others say a drilling practice known as "fracking," in which drillers shoot water, sand and chemicals into the shale to fracture it and free the gas, produces chemically tainted wastewater.

Volz's work came under attack by unnamed critics in the online newspaper Canada Free Press. The critics claimed he misrepresented facts on the report.

Some Volz supporters said he has been honest and objective about drilling's potential harm to the environment.

"He's been a wonderful resource for those who want to know what's happening," said Mel Packer, a community activist from Point Breeze. "I hope he continues to speak and finds ways to speak out."

Volz dismissed the online critics. He said there were some errors in his original report about the Josephine plant, but Pitt never challenged any of his research.

"I have made mistakes in all of my research, as we all do," he said. "Those errors were minor really and didn't have any influence over our overall recommendations or conclusions." He did not describe the errors.

Volz is scheduled to testify on Tuesday in Washington before the Senate Committee on Environment & Public Works, which is holding a hearing titled "Natural Gas Drilling: Public Health and Environmental Impacts." Robert Perciasepe, deputy administrator of the Environmental Protection Agency, also is scheduled to speak.

"If this were an infectious disease, this would be stopped immediately," he said about Marcellus shale drilling. "If this was Chi-Chis, and we had an outbreak of something, then all the spinach would be sequestered."

PITTSBURGH
TRIBUNE-REVIEW

Pitt: Departing shale drilling opponent free to speak his mind

By Luis Fabregas
PITTSBURGH TRIBUNE-REVIEW
Tuesday, April 12, 2011

A researcher and Marcellus shale drilling opponent who said he is leaving the University of Pittsburgh over "philosophical differences" can speak his mind about environmental dangers of natural gas extraction, Pitt officials said yesterday.

Researcher Conrad "Dan" Volz told the Tribune-Review for a story on Sunday that he would step down as director of Pitt's Center for Healthy Environments and Communities because the university said he could not be an advocate for public and environmental health causes. He said yesterday that he expects to leave by the end of May.

"The university does not oppose Dr. Volz's personally held views," said Allison Schlesinger, spokeswoman for Pitt's Graduate School of Public Health, where Volz worked since 2004. "He, like any other researcher or faculty member, has the academic freedom to study and research anything he'd like and to express his views based on that research and study."

Volz is scheduled to testify today before the Senate Committee on Environment & Public Works in Washington. He will discuss a March research report about nine toxic pollutants found in water from a stream near a wastewater treatment facility for Marcellus shale gas and oil extraction wells in Indiana County.

Asked whether the university reviewed the veracity of Volz's research work, Schlesinger said she could not comment because it is a personnel matter. She emphasized that Volz voluntarily stepped down without pressure from Pitt administrators. The center does not receive money from the gas industry.

Dr. Donald S. Burke, dean of the graduate school, declined requests for an interview. Volz's work was not published in an academic journal, which is standard practice for university researchers. Journal publication involves independent peer review of data.

Schlesinger said Volz "is not representing the University of Pittsburgh" when he testifies.

Critics questioned Volz's March 23 report on samplings of effluent from a facility that treats brine wastewater from oil and gas operations and discharges into Blacklick Creek. The criticism focused on sampling conducted on only one day at three-hour intervals and comparisons Volz made between treated effluent and federal drinking water standards and state environmental regulations.

Volz issued a revised report March 25. Among revisions the Tribune-Review found, he changed risk levels for certain pollutants from a general mean standard to specific toxic levels for adults and children.

Other changes acknowledged the facility's permit does not require treatment of bromide and some other agents used to extract gas through hydraulic rock fracturing but notes operators must notify the state "if they routinely discharge" certain amounts of pollutants.

Volz said last week that the errors did not change his conclusions, including the fact that pollutants such as barium, bromide and benzene were found in quantities "over either human health or ecological health standards." The levels, he said, pose a threat to recreationists who might drink the water, come in contact with it while kayaking or take fish from impacted waterways.

"I took samples, and we analyzed them," Volz said yesterday. "I don't know what could be wrong."

Pitt's Center for Healthy Environments and Communities will continue to conduct such research with a goal of improving the environment, Schlesinger said. The center operates with a $2 million grant from The Heinz Endowments.

Doug Root, a spokesman for the foundation, said he expects that funding will continue.

Luis Fabregas can be reached at lfabregas@tribweb.com or 412-320-7998.

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Canada Free Press

Pitt prof caught off base in new frack attack

- *Steve Milloy* Monday, March 28, 2011

University of Pittsburgh assistant professor Conrad (Dan) Volz issued a report on March 21 to scientists and the U.S. EPA claiming that natural gas industry is dumping carcinogenic agents into drinking water.

But just two days after a group of professionals reviewed the "report," Volz backtracked somewhat: apologizing, issuing a revised report, and explaining that numerous references he used in the report were incorrect and/or misstated. He nevertheless maintained that,

"... our overall environmental public health conclusions and recommendations have not changed despite these fundamental errors."

Volz's report continues to misstate, misrepresent and misuse facts, data and government criteria

But even with the "corrections," Volz's report continues to misstate, misrepresent and misuse facts, data and government criteria. Specifically, Volz:

- Demonstrates a lack of understanding and/or a disregard of federal and state environmental standards. For example, he relies heavily on Safe Drinking Water Act maximum contaminant levels (MCLs) that apply only at points of use for actual drinking water supply systems. He wrongly compares effluent discharges from a commercial treatment plant that discharges into a nearly-dead creek to these drinking water standards.
- Claims exceedances of drinking water standards despite that there are no drinking water intakes or uses — and none are possible because the creek is so polluted from abandoned coal mine discharges for miles above and below the brine treatment facility.
- Claims limits for contaminants such as strontium that cannot be found in federal or state regulations.
- Asserts that anglers frequent the stream and that it is listed for trout stocking. But there are no fish to be caught and the stream is not stocked due to mine water pollution that has degraded the entire stream. No trout have been stocked in Blacklick Creek for years.
- Erroneously picks primary and secondary water quality criteria that are not applicable for discharges into Blacklick Creek. He then compares them to discharge levels from his brief, one-day study to claim that people "are at risk." He called for an immediate shutdown of treatment plants while studies can be completed. But professional studies have already been completed showing the treatment plants are safe and these are available at Pennsylvania Department of the Environment (OPADEP) offices.
- Relies heavily on U.S.Agency for Toxic Substances and Disease registry (ATSDR) minimal risk levels (MRLs) for comparison of risks from brine treatment discharges in Blacklick Creek. According to the ATSDR, "An MRL is an estimate of the daily human exposure to a hazardous substance that is likely to be without appreciable risk of adverse noncancer health effects over a specified duration of exposure. These substance specific estimates, which are intended to serve as screening levels, are used by ATSDR health assessors and other responders to identify contaminants and potential health effects that may be of concern at hazardous waste

sites. It is important to note that MRLs are not intended to define clean up or action levels for ATSDR or other Agencies."

- Fails in any way to evaluate daily human exposure — an evaluation that risk assessment professionals perform by evaluating actual populations, usage and acute/chronic toxicity exposure scenarios. While MRLs are used only in an initial screening evaluation, Volz uses these levels to reach his conclusions, which were remarkably unaffected even when monumental errors were found and corrected from his initial report.
- Relied on sample results taken during one 24-hour period, three hours apart, for a total of eight samples during one day. We are aware of no federal or state agency that draws any risk-based conclusions from a study of results for just one day. Such a "study" ignores: seasonal variations, flow variation, stream mixing and dilution properties, unique thermal conditions and stream transects that are all critical components of studies that are essential for federal or state stream evaluations under the Clean Water Act or the federal Superfund law.
- Used this extremely limited data as the basis for speaking of "mean," "maximum," and "average" levels — as if a statistically significant population of results had been used. Again, no federal or state agency would reach conclusions on such limited data nor review it if submitted by any party.
- Includes an entire section devoted to "mass loadings" of pollutants in order to inform the readers of the "tons of pollutants" being discharged into Blacklick Creek. First, mass loadings have no scientific purpose. Only concentrations are of consequence and then only when considered over the relevant time/exposure period. The mass of "pounds or tons" of pollutants are presented to sensationalize and scare. If they were compared to things like road salt use, they will pale in comparison. In similar fashion, Volz seems to have converted part per million (ppm) concentrations to part per billion (ppb) concentrations so he could add three "zeros" to each number and make them appear much larger — even when the standard is in ppm.
- Mentions anglers who catch and eat fish from Blacklick Creek and swimmers who will absorb contaminants by "dermal contact." Governmental agencies who prepare or review such claims insist on studies of actual exposures. Volz only points to web sites indicating that locals "may be" using the creek. He claims such persons "are at risk" several times in the report.
- Claims water users are at risk because their wells "may" be able to pump water from Blacklick Creek. This ignores all science and the fact that net flow is into Blacklick Creek, not from it to underground waters.
- Claims that residents of Freeport on the Allegheny River are at risk despite that Freeport is dozens of miles away. Further, the stream is so extensively diluted at that point that the years of operation of brine treatment plants AND the decades of coal mine pollution have never come close to affecting that water supply system.
- Calls for immediate shutdown of the brine treatment plant while his concerns can be studied. The good news, however, is that all his concerns have already been addressed. The PADEP and EPA have reviewed and approved permits for the discharges on several occasions. That review and approval process ALWAYS includes an evaluation of all influent and effluent streams; any "reasonable potential" for water quality standards to be exceeded at any time of the year; and assurance that no drinking water supply can be adversely affected. Volz also calls for signs and warning to fishermen and residents. But Volz is years late in his concerns for the dangers of pollution of Blacklick Creek. Through the efforts of local conservation groups, a once totally dead stream as a result of abandoned coal mines is now showing some signs of life. As the stream improves, the standards for the brine treatment plants are tightened to assure no adverse impact. This system has been in place since the 1970's and continues to reap the desired benefit and goals of the Clean Water Act.

Volz's errors don't come as a surprise given that he has shed the mantle of scientist in favor of anti-fracking activism. As recently reported by CitizensVoice.com,

Volz repeatedly reminded people the [fracking] situation is political, urging them to vote out lawmakers who don't do what the people want.

Will Volz's junk science-fueled comments get him in the same water as this academic who spoke the scientific truth?

The University of Pittsburgh might want to get a grip on Volz before it winds up with another embarrassing Herb Needleman on its hands.

UNIVERSITY of ARKANSAS
SAM M. WALTON
COLLEGE of BUSINESS
Center for Business and Economic Research

Projecting the Economic Impact of the Fayetteville Shale Play for 2008-2012
Executive Summary

Produced by the
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Southwestern Energy Company

Study Date: March 2008

EXECUTIVE SUMMARY

In 2006, the Center for Business and Economic Research released an economic impact study of the newly developing natural gas industry related to the Fayetteville Shale. The Fayetteville Shale is an unconventional gas reservoir located on the Arkansas side of the Arkoma Basin, ranging in thickness from 50 to 325 feet and ranging in depth from 1,500 to 6,500 feet. That study concluded that from 2005 to 2008, economic output of over $5.5 billion and 9,683 jobs would be generated as a result of investments in the Fayetteville Shale. Those estimates were based on the best information available when the study was conducted; however, many of the companies involved in the Fayetteville Shale subsequently significantly accelerated their investment plans as the potential of the play was proved. Therefore, this report provides updated estimates, which better reflect the current investment plans of the companies involved, of the economic impact of the Fayetteville Shale natural gas industry on the state of Arkansas.

The direct activities associated with the development of the Fayetteville Shale that generate economic activity are: exploration, extraction, production, transportation, storage, and distribution. The counties in Arkansas where successful wells have been drilled are Cleburne, Conway, Faulkner, Franklin, Pope, Van Buren and White. The presence of the natural gas industry in Arkansas produces indirect (supply chain oriented) and induced (personal expenditure related) economic impacts. These added economic effects imply that when dollars are directly invested in the Fayetteville Shale, there is an associated multiplier.

In order to quantify the economic impact of the Fayetteville Shale Play, a survey was administered to the companies who make up and support the natural gas industry in central Arkansas. This survey had questions about planned expenditures and employment, risk factors like natural gas price declines and increases in the Arkansas severance tax, and the perceived economic impact of the development of the Fayetteville Shale. The numerical responses were used as inputs to the IMPLAN input/output model, which was used to estimate the indirect and induced effects associated with direct industry spending.

To provide a baseline of economic activity, expenditures and employment in the year 2007 were investigated. These impacts were substantial: $1.8 billion of direct expenditures led to total economic output of $2.6 billion and employment of 9,533 people.

	2007 Direct Impact	2007 Indirect Impact	2007 Induced Impact	2007 Total Impact	2007 Multiplier
Output	$1,797,349,728	$416,673,682	$387,068,671	$2,601,092,069	1.45
Employment	3,776.4	1,904.6	3,852.0	9,533.0	2.52

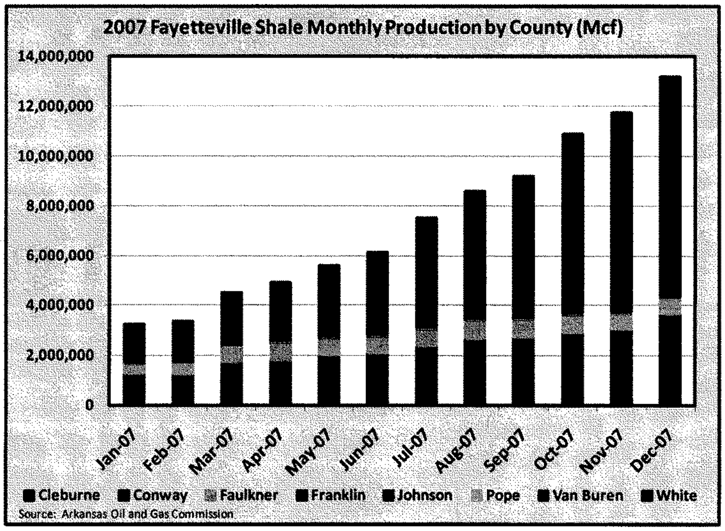
In 2007, the tax revenues from operations in the Fayetteville Shale were also significant for the state. More than $54.6 million in revenues were generated at the state level.

2007 Estimated State Taxes	Amount
Income Taxes from Employment	$5,023,891
Sales Taxes from Employment	$8,054,069
Income Taxes from Production	$34,216,210
Sales Taxes from Royalties	$3,359,130
Property Taxes for Schools from Production (2007 Assessment Year)	$3,703,650
Severance Taxes	$266,550
Arkansas State Taxes	**$54,623,500**

There were additional city and county sales and property taxes generated that are not included in this total. A weighted average of local sales tax rates was used to estimate the amount of sales tax generated for cities and counties. In 2007, that amount totaled just over $7.0 million. Local millage rates were used to calculate property tax revenues. These revenues were just over $1.3 million in 2007.

2007 Estimated Local Taxes	Amount
Sales Taxes from Employment	$4,698,207
Sales Taxes from Royalties	$2,339,776
Property Taxes from Production (2007 Assessment Year)	$1,303,067
Local Taxes	**$8,341,050**

In 2007, the companies continued to invest in the long term potential for production in the Fayetteville Shale. Total production from the Fayetteville Shale in 2007 was 88.8 billion cubic feet (Bcf) of natural gas, with a market value of approximately $651 million. This amount was less than 37 percent of the direct expenditures made by operating companies in that same year.



Source: Arkansas Oil and Gas Commission

Using results from the survey, estimates of economic activity from 2008 to 2012 were made. Over the next five year period, total economic activity of about $17.9 billion will be generated if the companies operating in the Fayetteville Shale make expenditures in the amounts and using the timing that they reported. Additionally, annual direct employment of about 4,600 people will result in total annual state employment of more than 11,000 people during the 2008 to 2012 time period.

Year	Direct Economic Output Impact	Indirect Economic Output Impact	Induced Economic Output Impact	Total Economic Output Impact	Average Multiplier
2008	$2,403,100,608	$618,168,513	$494,040,561	$3,515,309,701	1.46
2009	$2,312,800,224	$533,726,731	$480,145,885	$3,326,672,757	1.44
2010	$2,548,019,872	$556,154,598	$524,428,800	$3,628,603,211	1.42
2011	$2,634,311,552	$567,638,793	$532,898,064	$3,734,848,322	1.42
2012	$2,582,333,760	$555,837,508	$512,828,487	$3,650,999,970	1.41
Total	**$12,480,566,016**	**$2,831,526,143**	**$2,544,341,797**	**$17,856,433,961**	**1.43**

Year	Direct Employment Impact	Indirect Employment Impact	Induced Employment Impact	Total Employment Impact	Average Multiplier
2008	4,719.6	2,903.8	4,818.5	12,441.9	2.64
2009	4,497.7	2,327.1	4,588.2	11,412.9	2.54
2010	4,813.2	2,304.4	4,908.5	12,026.1	2.50
2011	4,789.3	2,284.7	4,884.0	11,958.0	2.50
2012	4,511.5	2,186.0	4,601.1	11,298.5	2.50

Additionally, significant income, sales, property, and severance tax revenues are projected to accrue to the state from 2008 to 2012. About $1.8 billion in state level taxes are projected to result from the direct, indirect, and induced effects of the activities in the Fayetteville Shale.

2008-2012 Estimated State Taxes	Amount
Income Taxes from Employment	$31,165,410
Sales Taxes from Employment	$49,962,937
Income Taxes from Production	$1,389,126,182
Sales Taxes from Royalties	$137,942,032
Property Taxes for Schools from Production (Assessment Years)	$143,797,376
Severance Taxes	$7,249,125
Arkansas State Taxes	**$1,759,243,062**

City and county tax revenues are also expected to be substantial over the 2008 to 2012 time period. Local sales and property taxes resulting from Fayetteville Shale activities are estimated to total over $150 million during the five year period.

2008-2012 Estimated Local Taxes	Amount
Sales Taxes from Employment	$29,145,047
Sales Taxes from Royalties	$80,466,185
Property Taxes from Production (Assessment Years)	$40,974,340
Local Taxes	**$150,585,572**

The output, employment, and tax estimates presented above are subject to a couple of obvious risks. The first is that the price of natural gas declines to a level where production in the Fayetteville Shale is no longer profitable for the companies operating there. According to the survey respondents, an average price of $6.21 per MMBTU is necessary for the forecasted investments to be made. A sustained decrease of $1.00 from that level could cause a 47 percent decrease in investment in the Fayetteville Shale. However, a sustained $1 increase in prices from that average level could cause average additional investment of 10 percent.

The second risk factor to the above projections is that the severance tax is raised to a level that causes the operating companies to reduce the magnitude or slow the timing of their investments in developing the Fayetteville Shale. Accordingly, a survey question was included, which asked for the investment and hiring response to a hypothetical 5 percent severance tax without any initial reductions or performance exemptions. The survey responses from Fayetteville Shale operators indicated that if the severance tax were increased to 5 percent, the average response would be a 13 percent decrease in investment in Fayetteville Shale activities. Employment and tax revenues would be proportionally affected as well. Any increases or declines in investment would also be subject to the multiplier effects estimated in this study.

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Disclaimer

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PENNSTATE

The Economic Impacts of the Pennsylvania Marcellus Shale Natural Gas Play: An Update

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May 24, 2010

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Executive Summary

Fully developed, the Marcellus Shale has the potential to be the second largest natural gas field in the world, behind only the South Pars/Asalouyeh field shared between the nations of Iran and Qatar. Converted to British Thermal Units (BTUs), the natural gas found in the Marcellus could be equivalent to the energy content of 87 billion barrels of oil, enough to meet the demand of the entire world for nearly three years.

In Pennsylvania, the development of these historic resources, while still in its infant stages, is credited with the creation of thousands of jobs and billions in annual revenue for the state. Over the next two years, this growth is expected to increase rapidly -- providing the Commonwealth with a steady supply of affordable, clean-burning energy, and creating the potential for a wholesale transformation of the energy landscape both across the state and throughout the nation.

Natural gas development stimulates the economy in two major ways: business-to-business spending and payments to land owners. Exploring, drilling, processing, and transporting natural gas requires goods and services from many sectors of the economy, such as construction, trucking, steelmaking, and engineering services. Gas companies also pay lease and royalty payments to land owners, who also spend and pay taxes on this income. Higher energy production stimulates employment, income, and tax revenues. This study estimates these economic impacts using an input-output model developed by the Minnesota IMPLAN Group, Inc., which is the same model used by the Pennsylvania Department of Labor (2010) in their study of green jobs.

During 2009, Marcellus gas producers spent a total of $4.5 billion to develop Marcellus shale gas resources. Using the IMPLAN modeling system, we estimate that this spending generated $3.9 billion in value added, $389 million in state and local tax revenues, and more than 44,000 jobs (see Table ES1). During 2009, natural gas output averaged 327 million cubic feet per day of natural gas equivalents, which includes dry natural gas and petroleum liquids. Output at year-end 2009 was over 500 million cubic feet per day.

Table ES1: Summary of Actual, Planned, and Forecast Economic Impacts

	Millions of 2010 Dollars				
Year	Value Added	State & Local Taxes	Employment	Wells Drilled	Output Bcfe / day*
2009	3,877	389	44,098	710	0.3
		Planned			
2010	8,039	785	88,588	1,743	1.0
2011	10,129	987	111,413	2,211	2.5
		Forecast			
2015	14,415	1,417	160,205	2,903	7.6
2020	18,853	1,872	211,909	3,587	13.5

* Bcfe is billion cubic feet of natural gas equivalents per day.

Based upon our survey, Marcellus producers plan to spend significantly more this year and next, generating more than $8 billion in value added in 2010 and another $10 billion during 2011 (see Table ES1). This higher economic activity generates almost $1.8 billion in additional state and local tax revenues during 2010 and 2011. Employment in the state expands by more than 88,000 jobs during 2010 and over 111,000 jobs during 2011.[1] This dramatic increase in Marcellus drilling activity has occurred during a period of general economic recession and relatively low natural gas prices. Natural gas production from the Pennsylvania Marcellus will likely average one billion cubic feet per day during 2010 and approach 2.5 billion cubic feet per day during 2011.

The projected economic impact from Marcellus activity in this report is very similar to the forecast made last year at a much earlier stage of Marcellus development. The minor differences can be attributed to a significant decline in natural gas prices and changes in the economy as a whole due to the current nationwide recession.

The Marcellus resource base is large and could support significant levels of drilling in the future. This study estimates a dramatic expansion of Marcellus gas production from slightly over 327 million cubic feet per day during 2009 to over 13 *billion* cubic feet per day by 2020. If this occurs, employment would expand by 200,000 jobs and annual gains in state and local taxes revenues would exceed $1 billion.

These benefits cannot simply be attributed to nature's bounty. Instead, their realization depends upon the Pennsylvania Marcellus maintaining its relative competitive position. Currently, there are at least five other major shale gas plays competing with the Marcellus, including the Barnett, Haynesville, Fayetteville, Woodford, and Eagle Ford formations as well as several shale formations in Canada. As production from these plays expands, prices for natural gas are likely to remain relatively low and pressures for cost containment will be intense.

Higher gas development costs in Pennsylvania due to regulations, climate conditions, topography, labor costs, and other structural factors are partially offset by city gate prices higher than the national average and the absence of a severance tax in Pennsylvania. The imposition of any significant severance tax on Marcellus natural gas output could induce a redirection of investment flows to other shale plays. Any revenues gained from a severance tax could be offset by losses in sales and income tax receipts resulting from lower drilling activity and natural gas production as producers shift their capital spending to other plays.

The development of the Pennsylvania Marcellus will have economic impacts on Pennsylvania beyond those measured in this report. If the Marcellus is developed to the extent envisioned in this report, the abundance of reliable, low cost natural gas could attract gas intensive manufacturing industries to expand capacity in Pennsylvania. Low cost natural gas also contributes to inexpensive electricity that enhances industrial development and economic growth. New industries would lead to additional gains in employment, output, and tax revenues. Moreover, developing the Marcellus could reduce the costs of the transition to an economy with lower greenhouse gas emissions.

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[1] Our previous study forecasted over 107,000 jobs created in 2010. The smaller job gains found here reflect new data in the IMPLAN model that reflects lower employment per unit of output due to the recession. Moreover, the estimates for 2010 and 2011 presented above are based upon a survey that reflects slightly lower spending from the projections last year, which were based upon higher natural gas prices.

Marcellus natural gas producers create jobs without direct government subsidies. With rising levels of public debt, this ability to produce domestic energy while generating income and wealth is valuable. In summary, the development of the Pennsylvania Marcellus increases domestic energy production, creates jobs, reduces government deficits, and on balance improves environmental quality.

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I. Introduction

This study provides an update on the economic impacts of the Marcellus shale gas industry in Pennsylvania (Considine, et al., 2009). This update discusses the results of our latest survey of producers to estimate current and planned industry spending, analysis of the economic impacts of this activity, and projections of future drilling, natural gas production, and related economic impacts. The evidence and analysis presented below indicates that the Pennsylvania Marcellus is rapidly emerging as a significant supplier of natural gas to the nation and a major source of jobs, income, and tax revenue to the Commonwealth of Pennsylvania.

For this study, we conducted a survey of producers to estimate drilling activity, spending levels, and production rates. The survey results clearly show a significant ramp-up in activity, with total spending increasing from $3.2 billion during 2008 to over $4.5 billion during 2009. Our survey also found that companies plan to increase their investment spending to $8.8 billion for 2010 and to over $11 billion in 2011. This evidence confirms that the Pennsylvania Marcellus industry is poised for a substantial take-off in development.

The survey and the findings of this report do not include historical or projected spending to upgrade interstate natural gas transmission pipelines, although it is recognized that Marcellus Shale development will result in significant new construction activity in that sector. Moreover, this report also does not consider development of several other organic shale formations that exist above and beneath the Marcellus.

Capital investments for Marcellus development have significant impacts on the economy of the Commonwealth of Pennsylvania. Producing natural gas requires exploration, leasing, drilling, and pipeline construction. These activities generate additional business for other sectors of the economy. For example, leasing requires real estate and legal services. Exploration crews purchase supplies, stay at hotels, and dine at local restaurants. Site preparation requires engineering studies, heavy equipment and aggregates. Drilling activity generates considerable business for trucking firms and well-support companies now based in Pennsylvania that in turn buy supplies, such as fuel, pipe, drilling materials, and other goods and services. Likewise, construction of pipelines requires steel, aggregates, and the services of engineering construction firms. Collectively, these business-to-business transactions create successive rounds of spending and re-spending throughout the economy. These higher sales generate greater sales tax revenues. Moreover, as businesses experience greater sales they hire additional workers. Greater employment increases income and generates higher income tax revenues.

Natural gas development also affects the economy through land payments. To access land to drill for gas companies negotiate leases with landowners. These agreements often provide an upfront payment or bonus after signing the lease and then production royalty payments during the life of the agreement if production is established. In 2008 alone, natural gas companies paid over $1.8 billion in these lease and bonus payments to Pennsylvania landowners. What do landowners do with these payments?

After paying taxes, lease and bonus income recipients may save a portion or spend the rest on goods and services from other sectors of the economy. For example, a farmer may spend his lease and bonus income to hire a carpenter to remodel his barn, who then buys lumber and supplies, and pays taxes on the net income he earns from the project.

Economists have long recognized these indirect and induced impacts from capital investments and the development of new industries. Countless studies have been conducted on these types of economic impacts arising from the construction of sports stadiums, hospitals, highways, wind turbines, and other capital investments. Nearly all of these studies have been conducted using input-output (IO) models of the economy. Input-output analysis accounts for the flow of funds between industries, households, and governments. These models provide a snapshot of the structure of the economy at a point in time and, thereby, an empirical basis for addressing a variety of questions surrounding economic development. For example, how many jobs are required to support a new industry or project?

These questions are asked so frequently that an economic research and consulting firm called Minnesota IMPLAN Group, Inc. in association with the University of Minnesota has been in business since 1993 providing detailed IO tables at the county and state level. Indeed, a recent study conducted by the Pennsylvania Department of Labor and Industry (2010) used the IMPLAN system to estimate the number of green jobs created in the Pennsylvania. The analysis presented below also uses the same IMPLAN model for Pennsylvania, finding that the $4.5 billion of spending by Marcellus producers during 2009 generated $3.8 billion in value added, $389 million in state and local tax revenue, and more than 44,000 jobs.

The prospects for future Marcellus development in Pennsylvania are promising. For example, the spending planned by Marcellus producers in 2011 could generate more than $10 billion in value added, nearly $1 billion in state and local tax revenues, and more than 100,000 jobs. Our forecasting model of future Marcellus natural gas drilling and production suggests that Pennsylvania could be producing more than 13 billion cubic feet of natural gas per day by 2020, which could make the Commonwealth the second largest producer of natural gas in the United States.

Unlike conventional oil and gas development expanding production from shale resources requires continuous drilling activity. Substantial cutbacks in drilling significantly reduce production after a few years because the gas output decline curve is very steep for shale gas reservoirs. Nevertheless, the sheer geographical size of the Marcellus supports significantly higher levels of drilling. Our forecast presented below estimates that more than 3,500 wells could be drilled in 2020, which is about the same level of drilling currently taking place in the Barnett shale play in Texas, which is the largest natural gas producing field in the U.S. This forecast is conservative because the Barnett is only one fourth the size of the Marcellus.

With higher natural gas production from the Marcellus royalty income increases substantially, and combined with greater business activity from additional drilling, significant flows of value added and income for the state are created. Our estimates suggest that in 2020 the Marcellus industry in Pennsylvania could be creating more than $18 billion in value added, generating more than $1.8 billion in state and local tax revenues, and supporting more than 200,000 jobs. Unlike renewable energy, clean coal, and nuclear power, Marcellus natural gas producers create jobs without government subsidies. With rising levels of public debt, this ability to independently generate income and wealth is essential.

These benefits cannot simply be attributed to nature's bounty. Instead, their realization depends upon the Pennsylvania Marcellus maintaining its relative competitive position. Currently, there are at least five other major shale gas plays competing with the Marcellus, including the Barnett, Haynesville, Fayetteville, Woodford, and Eagle Ford formations as well as several shale formations in Canada. As production from these plays expands, prices for natural gas are likely to remain relatively low and the pressures for cost containment will be intense. The absence of a severance tax in Pennsylvania along with city gate prices higher than the national average offsets higher costs associated with complex regulations, climate conditions, topography, higher labor costs, and other structural factors.

The imposition of any significant tax or other regulation on Marcellus natural gas output could induce a redirection of investment flows to other shale plays. Indeed, investment and production are increasing rapidly in these other shale plays, especially the Haynesville and Eagle Ford regions. Revenues gained from a severance tax could be offset by losses in sales and income tax receipts resulting from lower drilling activity and natural gas production as producers shift their capital spending to other plays. The inefficiencies of severance taxes are well recognized in the economic literature, such as the study by Deacon, Frech, and Johnson (1990), which finds that severance taxes reduce drilling, production, and employment.

The next section of this report describes the results from our survey of Marcellus producers operating in Pennsylvania. Section three discusses the economic modeling methodology and the estimated impacts of Marcellus development on output, employment, and tax revenues. The fourth section of this report discusses the projections of the future level of development and related economic impacts. The study concludes with a summary of our major findings and a brief discussion of the implications for policies that affect the long-term health and vitality of the industry.

II. Current Industry Activity

This project conducted a survey of natural gas producers operating in the Pennsylvania Marcellus. The survey form appears below in Appendix A and has three parts. The first set of questions sought to establish a baseline of economic and drilling activity with an estimate of total spending and wells drilled through year-end 2009. The second section asks for actual spending for 2008 and 2009 and planned spending for 2010-2011 for the following categories:

- Lease and bonus payments,
- Exploration,

- Upstream: drilling and completion,
- Midstream: pipeline and processing, royalties; and
- Other goods and services.

The third and final section requested data on the number of rigs operating, wells drilled to total depth, and production of dry natural gas and petroleum liquids on a quarterly basis for 2009.

To determine the proportion our sample represented of the industry, this project conducted a careful analysis of the inventory of wells started or "spudded" during 2009. The Pennsylvania Department of Environmental Protection (PADEP) publishes a list of well starts. To develop the well count for 2009 we first compiled the monthly spud report issued by the Pennsylvania Department of Environmental Protection (PADEP) into one data set. After this was completed we removed all wells that had duplicate API numbers because this told us that a well had been reported twice as the API number is the unique identifier issued to each well. This double reporting can occur if two separate drilling rigs are used on the same well, which is not uncommon for horizontal wells. The final steps in the process were to then sort the wells that were classified as Marcellus wells by the spud report and check these against Marcellus permits from the PADEP. This process was then repeated two more times to ensure that the same number was reached. The final result was 710 wells drilled during 2009 in Pennsylvania that could be verified as Marcellus Shale wells. A map of the wells drilled during 2009 appears below in Figure 1.

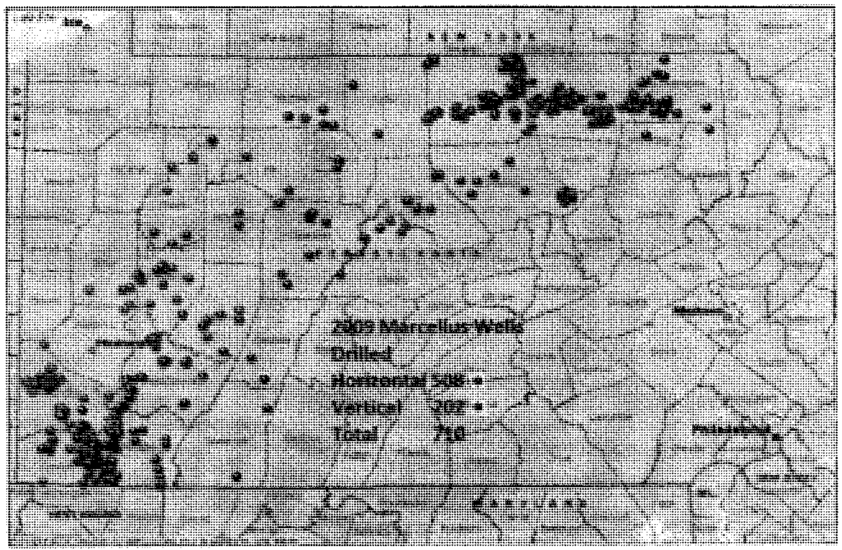

Figure 1: Marcellus wells started during 2009

Of the 710 wells drilled, 508 were horizontal and 202 were vertical wells. There was a noticeable increase in drilling activity in the northeastern counties of Susquehanna, Bradford, and Tioga with 282 wells drilled during 2009 from approximately 63 wells drilled during 2008. As Figure 1 above suggests, most of the wells drilled in these three northeastern counties were horizontal. Our estimate of 710 wells drilled in the Pennsylvania during 2009 should be considered conservative because the PADEP reports 763 wells started during 2009. The PADEP estimate was not used for this study because 53 wells could not be matched with a permit.

Our survey was distributed to members of the Marcellus Shale Coalition in early February 2010. Responses from twelve firms were completed during mid-April 2010. Based upon the well inventory analysis discussed above, these 12 firms drilled 528 during 2009, or more than 74 percent of the total wells started during 2009. Hence, to estimate the industry aggregates reported below, we multiplied all values from our survey by the ratio of 710 to 528. Clearly, using the 763 estimate of well starts reported by PADEP would lead to an over-estimate of the size of the Marcellus industry and the associated economic impacts.

The analysis now turns to the results of the survey on spending, drilling, and production. The estimated spending by Marcellus producers in Pennsylvania during 2008 and 2009 appears below in Table 1. Total spending increased from $3.2 billion during 2008 to more than $4.5 billion during 2009. Most of the increase came from higher expenditures on exploration, drilling, and pipeline and processing plant investments (see Table 1). Lease and bonus payments, which were the largest category at over $1.8 billion during 2008, declined slightly to $1.7 billion during 2009. The next largest expenditure category is upstream drilling and completion of wells, which amounted to over $857 million during 2008 and then over $1.7 billion during 2009. Mid-stream expenditures on pipelines and natural gas processing plants are the next largest category with over $329 million of spending during 2008 and approaching $700 million during 2009. The planned expenditures for the upstream and mid-stream segments of the industry discussed below will double yet again in 2010 and increase roughly 50 percent in 2011. As previously mentioned, this report does not include expenditures for any "downstream" activities such as expansion of interstate natural gas transmission, natural gas distribution or new businesses that may be created in Pennsylvania due to an abundant supply of reasonably priced natural gas.

Table 1: Spending in thousands of nominal dollars, 2008-2009

	2008	2009
Total Spending	3,224,577	4,535,304
Lease & Bonus	1,837,734	1,728,765
Exploration	121,940	243,831
Upstream: Drilling & Completion	857,751	1,700,435
Midstream: Pipeline & Processing	329,437	695,801
Royalties	22,183	54,683
Other	55,531	111,787

Not all of this spending occurred within Pennsylvania given that some supplies are imported from other regions and land income recipients may spend money outside the state. Our expenditure analysis from last year, however, indicated that 95 percent of this spending occurred within Pennsylvania during 2008. This indicates that a sizable well support industry has developed in Pennsylvania, particularly as corporations from the world oil and gas service business establish local headquarters in the Commonwealth.

Our survey asked producers for the number of rigs they were operating at the end 2008 and at the end of each quarter during 2009. The survey results appear below in Figure 2. At the end of 2008, 30 rigs were drilling in the Pennsylvania Marcellus (see Figure 2). By the end of the third quarter of 2009, the rig count more than doubled to 67 (see Figure 2). The leveling of the rig count during the fourth quarter of 2009 probably reflects seasonal factors, since operating during winter weather is more difficult.

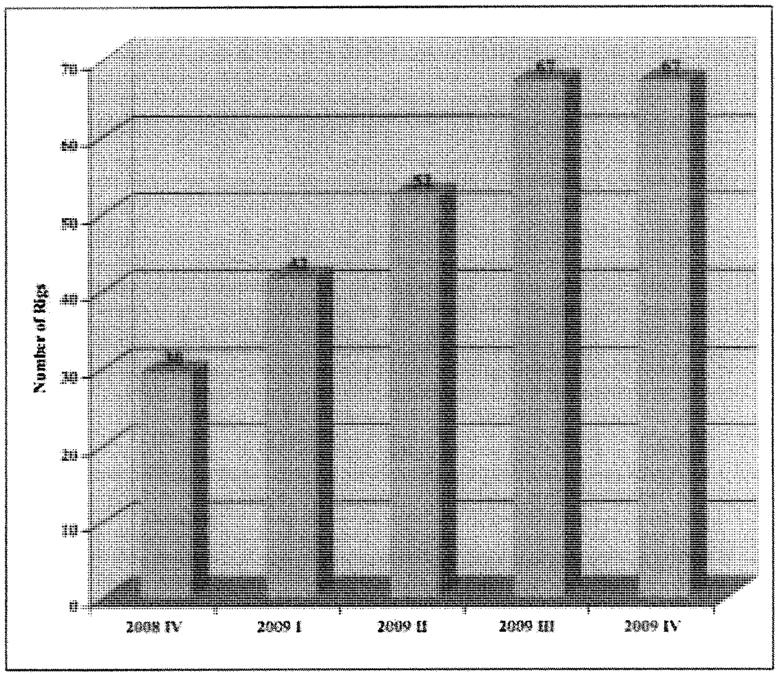

Figure 2: Marcellus Rigs operating in Pennsylvania by quarter, 2008-2009

This increase in rig capacity translated to more wells drilled. Charted below in Figure 3, are wells drilled to total depth. During 2009, 682 wells were drilled to total depth, which is consistent with our finding of 710 wells started. At the beginning of 2009, 54 percent of wells drilled to total depth were horizontal wells and by the end of the year that percentage increased to 84% (see Figure 3). On average 3.5 wells were drilled per operating rig, which implies that each rig took 25.5 days to drill a well to total depth.

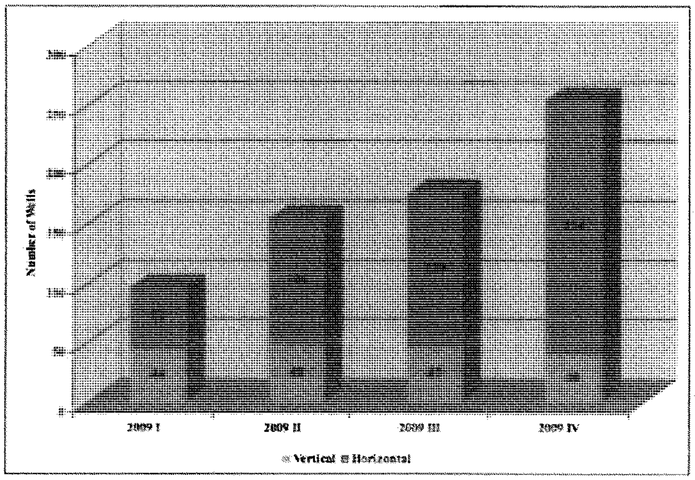

Figure 3: Marcellus Wells drilled to total depth during 2009

This drilling effort led to a steady increase in the number of operating wells. Figure 4 plots the number of producing wells. At the end of 2008, our sample suggests 280 wells were in production. One year later, 625 wells were operating (Figure 4).

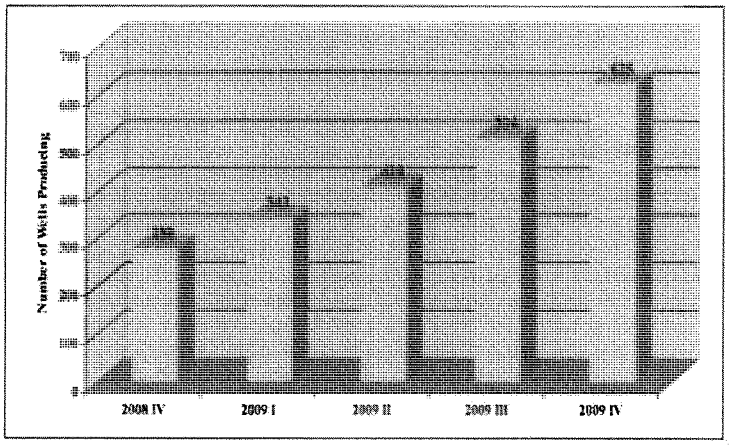

Figure 4: Marcellus wells producing in Pennsylvania

As these wells went into production, total natural gas production increased steadily. Figure 5 below reports quarterly average production of dry natural gas and natural gas liquids. During the last quarter of 2008, the Marcellus industry produced roughly 29 million cubic feet (mmcf) of natural gas equivalents per day. As Figure 5 illustrates, total production accelerated sharply, exceeding 200 mmcf per day by July and surpassing 550 mmcf per day by the end of the fourth quarter of 2009. Average annual production during 2009 was 327.7 million cubic feet per day.

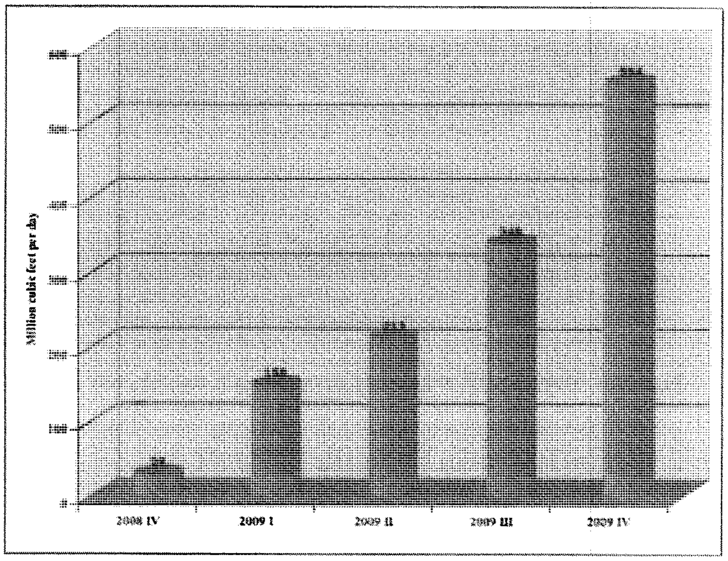

Figure 5: Quarterly production of natural gas equivalents

III. Economic Impacts

While the drilling rig may be the most widely associated symbol of natural gas development, there are many activities before and after drilling that generate significant economic impacts. Many people are required to identify lease properties, write leases, and conduct related legal and regulatory work. Seismic surveys also require manpower, local business services, and other provisions. Once a prospective site is identified, site preparation and drilling begins and with it the need for services, labor, and other locally supplied activities. If natural gas is found in commercial quantities, infrastructure, such as well production equipment and pipelines are installed, which again stimulates local business activity. Finally, as production flows from the well, royalties are paid to landowners and taxes paid to local governments. These expenditures stimulate the local economy and provide additional resources for community services, such as health care, education, and charities.

Expenditures at all stages of production generate indirect economic impacts as the initial stimulus from expenditures on natural gas development is spent and re-spent in other business sectors of the economy. For example, in developing mineral leases natural gas drilling companies employ the services of land management companies that in turn purchase goods and services from other businesses. These impacts are known as *indirect economic impacts*. The wages earned by these employees increase household incomes, which then stimulates spending on local goods and services. These impacts associated with household spending are called *induced impacts*. The total economic impacts are the sum of the direct, indirect, and induced spending, set off from the expenditures by Marcellus producers. These economic impacts are estimated by comparing gross output, value added, tax revenues, and employment in the local economy with and without Marcellus development.

Regional economic impact analysis using input-output (IO) tables and related IO models provide a means for measuring these economic impacts. Input-output analysis provides a quantitative model of the inter-industry transactions between various sectors of the economy and, in so doing, provides a means for estimating how spending in one sector affects other sectors of the economy. IO tables are available from Minnesota IMPLAN Group, Inc. based upon data from the Bureau of Economic Analysis in the US Department of Commerce.[2] This project uses these tables to estimate the economic impacts from the Marcellus industry outlays for natural gas exploration, development, and production. This study also identifies the specific economic sectors affected by the stimulus generated from natural gas development.

The Pennsylvania Marcellus is less than five years old and, therefore, is not included in the last update of the IO accounts for Pennsylvania. Accordingly, this study uses a technique proposed by Miller and Blair (2009) for introducing new industries into an input-output model of a regional economy. This approach requires estimating the input requirements of the new industry, which in our case are the purchases made by Marcellus gas producers from other sectors of the economy. Our previous report collected detailed accounting data from Marcellus producers to determine these inter-industry transactions. The location of firms supplying inputs to Marcellus producers and their respective industrial sector codes were determined from business database directors.

Like our previous report, the economic impacts reported below uses the IMPLAN system. This update, however, will not involve collecting detailed accounting information. Nevertheless, the detailed information collected last year is utilized for this update to link the data for spending categories above with the more disaggregated spending streams in the state level input-output system. In other words, our original study serves as a benchmark for our subsequent economic impact estimates. This benchmark approach is widely used by U.S. government agencies when they estimate economic activity.

The first set of estimated economic impacts reported in Table 2 involves gross output, which is equivalent to gross sales. The Marcellus gas industry provides a direct economic stimulus of $3.77 billion dollars to the local economy. This spending then leads to subsequent rounds of spending and re-spending by other firms on goods and services, which adds another $1.56 billion to total state gross output. These direct and indirect business activities generate additional income in the region, which then *induces* households to purchase $1.84 billion in additional goods and services. The sum of these direct, indirect, and induced impacts is more than $7.17 billion in 2009.

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[2] http://www.implan.com/index.html

Table 2: Impacts on Gross Output by Sector during 2009 in millions of 2010 dollars

Sector	Direct	Indirect	Induced	Total
Ag, Forestry, Fish & Hunting	13.5	11.8	6.3	31.6
Mining	991.9	19.4	3.8	1,015.1
Utilities	42.2	43.7	38.3	124.2
Construction	829.2	18.6	14.0	861.9
Manufacturing	139.4	239.3	123.1	501.9
Wholesale Trade	455.7	102.2	84.8	642.7
Retail trade	228.2	16.3	197.7	442.2
Transportation & Warehousing	90.0	77.7	39.7	207.4
Information	22.1	129.5	92.9	244.5
Finance & Insurance	44.3	159.6	214.4	418.4
Real estate & rental	220.6	143.9	315.8	680.3
Professional- scientific & tech services	174.0	310.9	87.1	572.1
Management of companies	0.0	84.1	19.5	103.6
Administrative & waste services	26.6	93.0	43.0	162.5
Educational services	87.9	1.7	39.2	128.8
Health & social services	190.8	3.3	290.9	484.9
Arts- entertainment & recreation	35.3	6.0	34.1	75.5
Hotel & food services	87.6	26.1	81.0	194.7
Other services	63.3	39.0	83.8	186.2
Government & Misc.	25.8	30.9	34.5	91.2
Total	3,768.6	1,557.2	1,843.8	7,169.6

So for every $1 that the Marcellus industry spends in the state, $1.90 of total economic output is generated. This estimate is considerably above the 1.34 multiplier found by Baumann et. al (2002) in their study of the impacts of oil and gas activities on the Louisiana economy. In a study of the economic impacts of the natural gas industry in New Mexico, Walker and Sonora (2005) assume an output multiplier of 1.43. The study by Snead (2002) finds an output multiplier of 1.55 for Oklahoma. This study's higher multiplier probably reflects our detailed expenditure analysis in our benchmark year 2008 based upon company accounting data, which provide a more accurate measurement of inter-industry purchases.

A more meaningful estimate of economic impacts is value added, which subtracts inter-industry purchases from gross output and measures the returns to labor and capital (see Table 3). Using this measure, the Marcellus gas industry in Pennsylvania directly added over $1.98 billion to the economy of Pennsylvania, which then generated indirect and induced impacts that increased the total value added generated in the Commonwealth by $3.87 billion. In other words, the total economic impact of the Marcellus industry measured by valued added was $3.87 billion during calendar year 2009.

Table 3: Impacts on Value Added by Sector during 2009 in millions of 2010 dollars

Sector	Direct	Indirect	Induced	Total
Ag, Forestry, Fish & Hunting	3.7	3.9	2.2	9.8
Mining	501.0	11.0	2.4	514.4
Utilities	29.9	28.4	27.4	85.8
Construction	330.1	10.7	8.4	349.2
Manufacturing	34.4	62.1	29.0	125.5
Wholesale Trade	306.0	68.6	56.9	431.5
Retail trade	152.0	11.1	133.0	296.1
Transportation & Warehousing	49.5	48.3	22.9	120.7
Information	9.2	51.6	37.4	98.2
Finance & Insurance	23.8	92.6	112.2	228.7
Real estate & rental	163.1	96.9	232.8	492.8
Professional- scientific & tech services	91.2	178.2	50.9	320.3
Management of companies	0.0	50.6	11.8	62.4
Administrative & waste services	14.9	59.0	26.6	100.5
Educational services	50.2	0.9	23.0	74.2
Health & social services	119.1	2.0	179.8	300.9
Arts- entertainment & recreation	14.9	3.2	14.8	32.9
Hotel & food services	44.7	12.7	39.4	96.9
Other services	33.0	20.8	42.1	95.9
Government & Misc.	11.2	15.1	13.8	40.1
Total	1,982.0	828.0	1,066.5	3,876.5

Like the impacts on gross output by sector, the increases in value added by sector generated by the Marcellus industry are broad based. Value added generated in the mining, real estate and rentals, and wholesale trade sectors are $514, $493, and $431 million dollars respectively (see Table 3). Marcellus development generates value added in excess of $300 million in the construction, scientific and technical services, health and social services. The retail trade and finance and insurance sectors are also stimulated more than $200 million dollars of value added (see Table 3). Overall, the Marcellus gas industry generates a rather widespread increase in value added across many sectors of the Pennsylvania economy.

This broad based increase in value added stimulates employment in the region. The Marcellus industry purchases of goods and services, their royalties to landowners, and tax payments directly create more than 21,000 jobs in Pennsylvania. Indirect and induced impacts create even more jobs so that total jobs created by the Marcellus industry is estimated at 44,098 (see Table 4). An estimated 5,934 jobs are created in retail trade, 5,272 in construction, 4,943 in health and social services, 3,219 in professional services, 3,195 in wholesale trade, and 2,937 in mining. Like our estimated impacts on gross output and value added, these diverse job gains reflect the widespread stimulus to the Pennsylvania economy from the supply chain required to develop Marcellus Shale gas.

Table 4: Employment Impacts during 2009 in number of Jobs

Sector	Direct	Indirect	Induced	Total
Ag, Forestry, Fish & Hunting	103	130	79	311
Mining	2,878	51	8	2,937
Utilities	73	45	41	159
Construction	4,989	161	122	5,272
Manufacturing	239	574	222	1,034
Wholesale Trade	2,266	508	421	3,195
Retail trade	2,938	225	2,771	5,934
Transportation & Warehousing	613	617	303	1,533
Information	61	322	239	621
Finance & Insurance	164	700	847	1,711
Real estate & rental	446	586	596	1,629
Professional- scientific & tech services	738	1,938	543	3,219
Management of companies	0	302	70	372
Administrative & waste services	326	1,340	600	2,266
Educational services	1,070	23	574	1,667
Health & social services	1,984	22	2,938	4,943
Arts- entertainment & recreation	401	113	403	917
Hotel & food services	1,368	445	1,393	3,206
Other services	968	427	1,238	2,633
Government & Misc.	154	203	180	538
Total	21,778	8,732	13,587	44,098

These employment impacts are within the range reported in the literature. The results of this study indicate that for every $1 million of output created by natural gas production in the Pennsylvania Marcellus, 6.9 jobs are created. This metric is within the range of employment multipliers of 3.0, 6.7, and 7.7 found by Walker and Sonora, Baumann et. al, and Snead et. al. respectively but more than the estimates reported by Perryman (2009).

The higher economic output and greater employment by the Marcellus gas industry generate additional tax revenues for federal, state and local governments. These impacts are reported below in Table 5. State and local tax revenues for Pennsylvania increase slightly over $389 million with the bulk of that coming from indirect business taxes of $289 million. Federal taxes paid by Pennsylvania increase by $1.05 billion from Marcellus development with most of the increase coming from higher social security taxes and personal income taxes paid as more people are working and receiving income.

The Allegheny Conference (2009) recently found that Pennsylvania's pre-Marcellus oil and gas industry in total generated $7.1 billion in economic impacts. Oil and gas producers drilled a total of 4,189 wells in Pennsylvania during 2007. Hence, according to their estimates every well drilled generates $1.7 million in economic impacts. In contrast, our study finds that each Marcellus well generates $6.2 million in economic impacts. This difference reflects the higher cost of Marcellus wells and the greater resource requirements for the supply chain.

Table 5: Tax Impacts during 2009 in millions of 2010 dollars

			State and Local Taxes			
Description	Employees	Proprietor	Business	Households	Corporations	Total
Dividends					22.38	22.38
Social Insurance						
Employee Contr.	0.76					0.76
Employer Contr.	3.26					3.26
Indirect Business						
Sales			117.85			117.85
Property			124.32			124.32
Motor Vehicle Lic.			2.59			2.59
Other			36.37			36.37
S/L Fees			8.16			8.16
Corporate Profits					14.95	14.95
Personal Income						
Income				47.14		47.14
Fines & Fees				6.89		6.89
Motor Vehicle Lic.				2.25		2.25
Property				1.09		1.09
Other (Fish/Hunt)				1.06		1.06
Total State & Local	4.02		289.28	58.43	37.33	389.06
			Federal Taxes			
Social Insurance						
Employee Contr.	241.96	50.54				292.51
Employer Contr.	244.70					244.70
Indirect Business						
Excise			35.79			35.79
Custom Duty			16.67			16.67
Fed Fees			27.52			27.52
Corporate Profits					124.61	124.61
Personal Income				315.02		315.02
Total Federal	486.66	50.54	79.98	315.02	124.61	1,056.81

IV. Planned Industry Spending and Economic Impacts for 2010 and 2011

Our survey of Marcellus natural gas producers operating in Pennsylvania also asked for estimates of planned industry spending for 2010 and 2011, which are reported below in Table 6. Producers plan to spend more than $8.7 billion during 2010. While lease and bonus payments decline slightly from 2009 levels, producers expect that they will remain more than $1.5 billion for the next two years. The big increase over this year and next are for the upstream and mid-stream segments of the industry, with spending increasing from $2.4 billion during 2009 to $6.3 and $8.1 billion for 2010 and 2011 respectively.

The economic impacts from this planned spending are likely to be significant. To estimate these possible impacts, this study ran the IMPLAN model for Pennsylvania for these two years, adjusting for the effects of inflation on real value added. Below is a summary of the total economic impacts on value added and employment by sector. The economic contribution of the Marcellus gas industry as measured by value added rises to

$8 billion in 2010 and to over $10 billion in 2011. In other words, the Marcellus industry increases the gross state product of Pennsylvania.

Table 6: Planned Marcellus Spending in thousands of nominal dollars, 2010-2010

	2010	2011
Total Spending	8,773,731	11,010,602
Lease & Bonus	1,602,187	1,577,748
Exploration	493,910	486,972
Upstream: Drilling & Completion	4,468,292	6,489,792
Midstream: Pipeline & Processing	1,785,878	1,586,278
Royalties	252,463	633,135
Other	171,001	236,677

Higher gross state product implies greater employment. For example, our estimates suggest that the level of employment in the state could increase over 88,000 due to Marcellus industry activity during 2010 and well over 100,000 during 2011. As a result of higher real output and employment, state and local tax revenues could be $785 and $987 million higher during 2010 and 2011 respectively. In short, the Marcellus shale gas industry adds true, real value to the economy and in the process creates jobs and improves the fiscal health of the Commonwealth.

Table 7: Value Added and Employment Total Impacts from Planned Spending

	Value Added in Millions of 2010 Dollars		Employment Gains in Number of Jobs	
Sector	2010	2011	2010	2011
Ag, Forestry, Fish & Hunting	19.3	24.2	590	740
Mining	1,287.8	1,637.5	7,367	9,369
Utilities	157.9	197.5	312	391
Construction	864.9	1,099.3	13,061	16,601
Manufacturing	247.8	311.4	2,113	2,660
Wholesale Trade	1,012.7	1,283.9	7,499	9,507
Retail trade	544.0	680.7	10,748	13,435
Transportation & Warehousing	261.2	329.9	3,293	4,156
Information	194.9	244.9	1,224	1,538
Finance & Insurance	447.5	562.0	3,364	4,226
Real estate & rental	855.9	1,067.0	2,851	3,556
Professional- scientific & tech services	723.9	916.0	7,229	9,145
Management of companies	135.9	171.7	812	1,025
Administrative & waste services	211.0	266.0	4,761	6,002
Educational services	105.3	129.3	2,441	3,006
Health & social services	511.5	636.8	8,438	10,507
Arts- entertainment & recreation	54.4	67.6	1,540	1,915
Hotel & food services	158.8	197.1	5,355	6,658
Other services	169.2	211.2	4,567	5,693
Government & Misc.	75.5	94.6	1,024	1,284
Total	8,039.5	10,128.6	88,588	111,413

V. Forecasts of Marcellus Industry Activity and Economic Impacts out to 2020

As the above analysis demonstrates, the economic impacts of the Marcellus gas industry are driven by inter-industry spending to support drilling activity and payments to land owners. As the Marcellus is developed, royalties will dominate payments to land owners, eventually exceeding lease and bonus payments. Therefore, to project future royalties a forecast of natural gas production is required.

Natural gas production in any period is the sum of production from current and all previous vintages of producing wells. The production profile of typical shale wells entails a rather sharp initial decline in the production rate and after a few years a much slower rate of decline. Several Marcellus Shale operators have published typical decline curves for horizontal wells based on their early drilling experience in Pennsylvania. Since the play is so new, with very few wells having more than even a one year producing history, companies estimate reserves on the basis of early life production results, reservoir models, and comparisons with longer term well performance in more mature shale plays.

The production decline curve used in this study is displayed below in Figure 6, which is the basis for the production forecast below. This curve is on the low end of publicly released decline curve information released by five major Marcellus Shale operators during the second half of 2009. The estimated production over the first 30 years is 2.8 billion cubic feet, after 50 years the yields is 3.5 bcf. Given this decline curve, average annual production from a Pennsylvania Marcellus horizontal well is over 500 mmcf during the first year, about 250 mmcf during the second, after 8 years about 100 mmcf, and roughly 30 mmcf per year after 30 years of production.

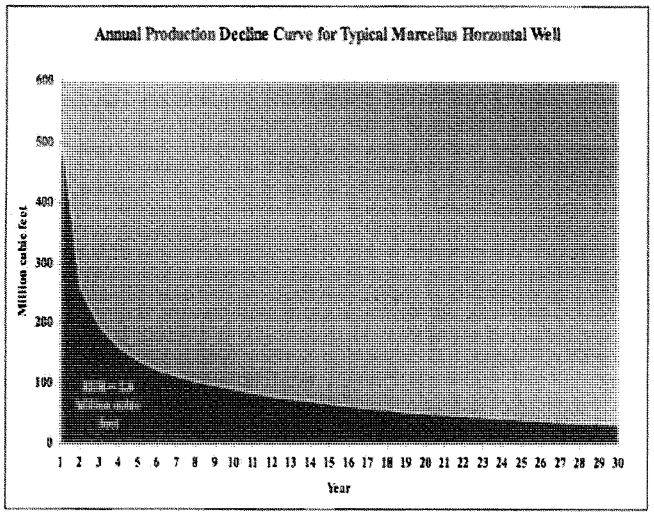

Figure 6: Marcellus Production Decline Curve

As the discussion above demonstrates, not all wells drilled in the Marcellus are horizontal. Vertical wells have a similar decline curve but substantially lower output. Accordingly, this study assumes that annual production from a vertical Marcellus well is slightly less than 30 percent of the output from a horizontal well.

Bottlenecks in infrastructure development are another feature of the industry that must be considered in projecting future production. There are widespread reports of producers drilling wells to secure leases and then capping them until pipeline infrastructure can be built to carry the gas to market. Given time lags in constructing pipeline gathering systems and connections to major interstate pipeline networks, this study assumes a one-year lag between the time a well is drilled and when it is producing marketable gas.

The planned level of spending by Marcellus producers, suggests that over 1,700 wells could be drilled during 2010. This estimate is based upon an average expenditure for exploration, upstream, and downstream production of over $3.8 million for wells drilled to total depth observed during 2009. Similarly, spending plans suggest over 2,200 wells could be drilled during 2011. Between 2012 and 2020, this study uses the drilling forecast equation developed by Considine, et. al. (2009) that predicts drilling activity based upon natural gas prices. The prices used in this study are futures prices for natural gas from the New York Mercantile Exchange reported on April 15, 2010 adjusted for inflation. These real, inflation adjusted prices in 2010 dollars are $5.42 per thousand cubic feet (mcf) in 2010 and gradually increase to over $6 per mcf by 2020 for an average annual real rate of increase of two percent. Given these assumptions, our projection of future Marcellus gas drilling is displayed below in Figure 7. Drilling activity increases from 2,500 wells drilled during 2012 to over 3,500 wells drilled during 2020.

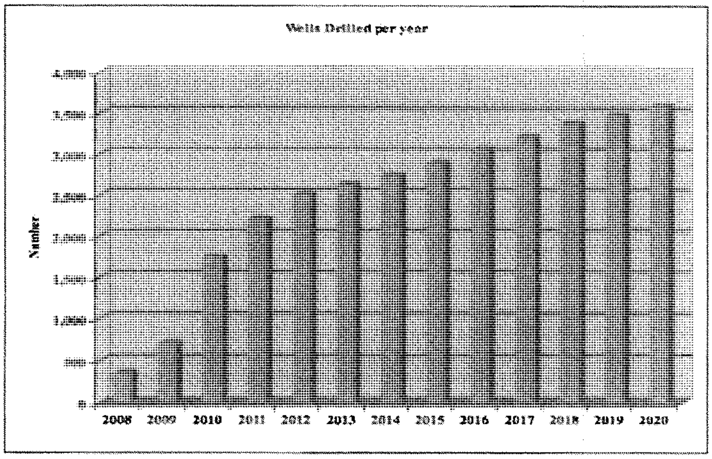

Figure 7: Forecast for Marcellus Natural Gas Drilling, 2009-2020

Following recent trends, this study assumes that the share of vertical wells in total well drilled will decline to 10 percent by 2020. Given this and previous assumptions, this study projects a trajectory of natural gas production for the Pennsylvania Marcellus that is displayed below in Figure 8. During 2010, average annual production could approach one billion cubic feet per day. Given planned drilling during 2010, production could exceed 2.5 bcf per day by 2011, exceeding Pennsylvania's natural gas consumption and making the Commonwealth a natural gas exporter. Pennsylvania could be producing over 7 billion cubic feet of gas per day by 2015, which is more than Wyoming's production during 2008. Production could reach 13 bcf per day by 2020, which would make Pennsylvania the second largest producer of natural gas behind Texas.

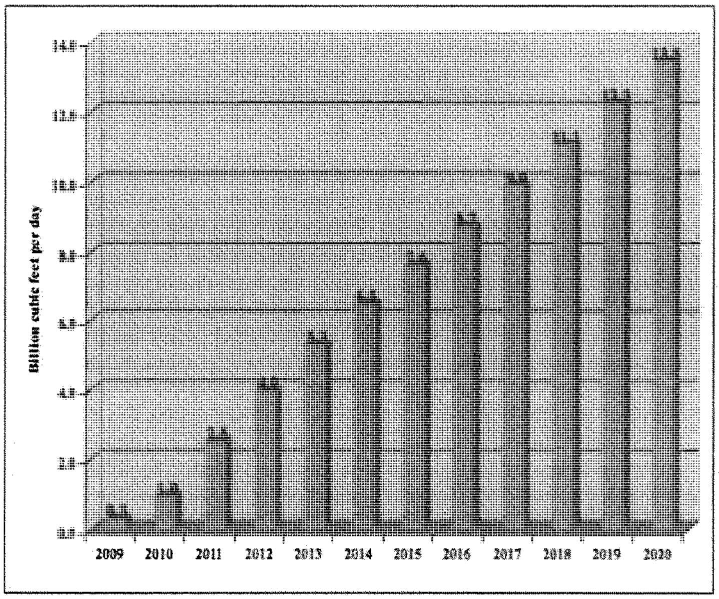

Figure 8: Forecast for Marcellus Natural Gas Production, 2010-2020

Change in Pennsylvania's regulatory and tax policies that would raise the relative cost of Marcellus development could reduce the pace of drilling and, hence, future natural gas production and other economic impacts discussed in this report. If the current tax and regulatory policies remain in place, there are several reasons why the above forecast could be conservative. First, the productive capacity for a typical Marcellus well could be greater than indicated by the type curve used in these projections. Second, the level of drilling could be substantially higher than the levels projected here. At 3,500 wells by 2020, drilling density would remain quite low compared to other shale gas plays. If these projections are borne out, the Pennsylvania Marcellus could have a profound effect on the U.S. natural gas market.

This level of future drilling and development activity will significantly stimulate the Pennsylvania economy. Estimates of these future economic impacts are summarized in Table 8. During 2015, the Marcellus gas industry could be generating more than $14 billion in value added, $1.4 billion in state and local tax revenues, and increasing state employment by 160,000. In 2020, the impacts grow even larger with over $18 billion in value added, over $1.8 billion in state and local tax revenue, and a workforce 200,000 larger.

Table 8: Forecast Economic Impacts

	Millions of 2010 dollars		
Year	Value Added	State & Local Taxes	Jobs
2015	14,415	1,417	160,205
2020	18,853	1,872	211,909

VI. Summary and Conclusions

This study provides an update of the impacts of the Marcellus gas industry on the economy of the Commonwealth of Pennsylvania. This update was accomplished by conducting a survey of natural gas producing companies drilling the Marcellus play in Pennsylvania. The companies responding to our survey accounted for more than 74 percent of the Marcellus wells drilled during 2009. Our survey results reveal that the industry spent over $4.5 billion on Marcellus development during 2009. By the end of 2009, our estimates suggest that there were over 625 producing Marcellus wells in Pennsylvania producing over 500 million cubic feet of natural gas equivalents per day.

Our estimated economic impacts for 2008 and 2009 are quite close to our estimates from last year. The estimates for 2008 changed slightly since this update uses revised and updated economic data for 2008. The estimated impacts for 2009 are also very similar to the projections from last year's report. During 2009, the Marcellus gas industry increased Pennsylvania's value added by $3.8 billion, generated $389 million in state and local taxes, and created more than 44,000 jobs.

Our survey also asked Marcellus natural gas producers how much they planned to spend for 2010 and 2011. Based upon the results from this survey, the near term outlook for the Marcellus gas industry in Pennsylvania is even more robust than we anticipated last year. Based on these spending plans, the Marcellus industry in Pennsylvania could generate more than $8 billion in value added during 2010. This economic activity would generate more than $785 million in state and local taxes and would cause job gains to double yet again to over 88,000 (see Table 9). The rate of growth tapers somewhat in 2011. Nonetheless, the economic impacts are impressive with nearly $1 billion in additional tax revenues for the state and 100,000 plus jobs.

Looking beyond the planning horizon and employing some conservative assumptions about drilling and production profiles, the outlook for Marcellus production is remarkable. By 2015, the Pennsylvania Marcellus could be producing over 7 billion cubic feet per day, substantially exceeding all gas output from offshore federal waters.

Marcellus natural gas production could nearly double again by 2020, with more than 13.5 billion cubic feet per day, which would make Pennsylvania second only to Texas in natural gas production. The economic impacts of this level of production are very significant, dramatically improving the fiscal position and job market in the Commonwealth of Pennsylvania.

Table 9: Summary of Estimated, Planned, and Forecast Economic Impacts

	Millions of 2010 dollars		
Year	Value Added	State & Local Taxes	Jobs
2008	2,556	265	30,137
2009	3,877	389	44,098
		Planned	
2010	8,039	785	88,588
2011	10,129	987	111,413
		Forecast	
2015	14,415	1,417	160,205
2020	18,853	1,872	211,909

Large-scale development of the Marcellus is reshaping the economic landscape of Pennsylvania. Strategies and policies that encourage growth of the Marcellus gas industry will generate significant economic and environmental benefits for the Commonwealth of Pennsylvania, transforming the Pennsylvania to a net natural gas exporter while creating hundreds of thousands of jobs and generating billions of dollars in additional output, income, and tax revenues.

There are additional economic impacts not estimated in this report. The availability of low cost natural gas supplies could stimulate the expansion of manufacturing capacity in the Commonwealth of Pennsylvania, such as steel, glass, foundries, chemicals, fertilizers, and other natural gas intensive industries. Such an expansion would further stimulate the supply chain and generate additional job and tax revenues gains. Abundant gas supplies also could reduce the cost of achieving reductions in greenhouse gas emissions as well as emissions of NO_x, SO_2, and other pollutants. Thus, the additional natural gas produced from the Marcellus would propel Pennsylvania's economy forward while reducing greenhouse gas emissions.

Despite the enormous potential of the Marcellus, Pennsylvania policy makers need to understand that the Marcellus competes for scarce investment capital with other shale plays around North America. Policies that raise the costs of developing the Marcellus relative to these other shale plays could reduce Marcellus production, job creation, and tax revenue growth.

Many people believe clean, domestic energy production need not impinge upon economic growth. Marcellus shale gas producers are transforming this belief into a new reality.

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Appendix A: Survey Form

Table A1: Survey Form for Measuring Marcellus Shale Activity

Confidential Survey: Pennsylvania Marcellus Shale Gas Activity

Company: ____________________

Contact Name: ____________________

Phone Number: ____________________

Email Address: ____________________

Note: All values should be for the Pennsylvania Marcellus on a calendar year basis
Data should pertain to wells operated by the company (Gross Operated Basis)

Cumulative as of year end 2009 (inception to date)	
Total Spending 1,000$	
Wells drilled to total depth, #	
Vertical	
Horizontal	

		Actual		Planned	
	Units	2008	2009	2010	2011
Total Spending	1,000 $				
Lease & Bonus	1,000 $				
Exploration	1,000 $				
*Upstream: Drilling & Completion**	1,000 $				
*Midstream: Pipeline & Processing**	1,000 $				
Royalties	1,000 $				
Other	1,000 $				

		Year End	2009 end of quarter			
Rig & Well Count	Units	2008	I	II	III	IV
Rigs Operating	#					
Wells producing	#					

			2009			
Drilling & Production	Units	2008	I	II	III	IV
Wells Drilled to total Depth	#					
Vertical	#					
Horizontal	#					
Production that you operate						
Gross Dry Natural Gas	mcf					
Petroleum Liquids	mmbtu					

An Emerging Giant: Prospects and Economic Impacts of Developing the Marcellus Shale Natural Gas Play

PENNSTATE

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Executive Summary

Many Pennsylvanians are aware of the recent surge in natural gas leasing activity. The vast majority of citizens, however, do not fully appreciate the scale of change such development will unleash. This report educates the public on the current size, economic impacts, and future prospects of the Marcellus shale gas industry in Pennsylvania.

The Marcellus shale is the largest unconventional natural gas reserve in the world. While reserve estimates should be considered somewhat uncertain at this early stage, as each new Marcellus well is completed, estimates of recoverable reserves of at least 489 trillion cubic feet seem increasingly reasonable. The market and strategic value of the Marcellus Shale will no doubt grow as conventional natural gas reserves are depleted and our economy adjusts to a path with lower greenhouse gas emissions. Natural gas has considerably lower carbon content than petroleum and coal. The market share of natural gas in electric power generation continues to expand and opportunities for switching from petroleum to natural gas beckon in the transportation sector.

This study finds that the Marcellus gas industry in Pennsylvania generated $2.3 billion in total value added, more than 29,000 jobs, and $240 million in state and local taxes during 2008. With a substantially higher pace of development during 2009, economic output will top $3.8 billion, state and local tax revenues will be more than $400 million, and total job creation will exceed 48,000.

Advances in drilling technology and highly productive wells make the Marcellus play very attractive. This study finds that activity in the Marcellus will continue to expand. Natural gas production from the Pennsylvania Marcellus could rise to almost 4 billion cubic feet BCF per day by 2020. The direct spending by Marcellus producers to support drilling operations and the royalty and other payments to land owners will stimulate business activity throughout the economy and induce households and businesses to spend earnings on additional goods and services. This study finds that the Marcellus industry could be generating $13.5 billion in value added and almost 175,000 jobs in 2020. The present value of additional state and local taxes earned from Marcellus development between now and 2020 is almost $12 billion.

Governor Rendell recently proposed a severance tax on natural gas production. This study finds that this tax cannot be passed on to consumers and, therefore, drilling activity would decline by more than 30 percent and result in an estimated $880 million net loss in the present value of tax revenue between now and 2020. Severance tax revenue gains are more than offset by declining state and local income taxes resulting from lower drilling activity under the severance tax. The high level of drilling activity in Pennsylvania is a function of relatively lower taxes. This competitive advantage should be maintained as the Marcellus competes for capital and labor with other shale plays around the nation. Imposing a severance tax at this early stage of development could significantly inhibit the growth of the Marcellus gas industry in Pennsylvania. Proposals to regulate hydraulic fracturing under the federal Safe Drinking Water Act pose yet another serious threat to the development of the Marcellus Shale and other unconventional gas sources.

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CONSERVATION COMMISSION

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The documentary *Gasland* has attracted wide attention. Among other things, it alleges that the hydraulic fracturing of oil and gas wells has contaminated nearby water wells with methane in a number of states including Colorado. Because an informed public debate on hydraulic fracturing depends on accurate information, the Colorado Oil and Gas Conservation Commission (COGCC) would like to correct several errors in the film's portrayal of the Colorado incidents.

Background

Methane is a natural hydrocarbon gas that is flammable and explosive in certain concentrations. It is produced either by bacteria or by geologic processes involving heat and pressure. Biogenic methane is created by the decomposition of organic material through fermentation, as is commonly seen in wetlands, or by the chemical reduction of carbon dioxide. It is found in some shallow, water-bearing geologic formations, into which water wells are sometimes completed. Thermogenic methane is created by the thermal decomposition of buried organic material. It is found in rocks buried deeper within the earth and is produced by drilling an oil and gas well and hydraulically fracturing the rocks that contain the gas. In Colorado, thermogenic methane is generally associated with oil and gas development, while biogenic methane is not.

The analytical methods use to differentiate between the two types of methane are well-known, scientifically accepted, and summarized in a well-known presentation by Dennis Coleman and papers by I.R. Kaplan and Dennis Coleman. These works, in turn, cites nearly 75 other references related to the topics of methane generation, "fingerprinting," forensic investigations, and stable isotope geochemistry.

Based upon our review of hundreds of Colorado gas samples over many years, the COGCC is able to differentiate between biogenic and thermogenic methane using both stable isotope analysis of the methane and compositional analysis of the gas. In the Denver-Julesburg and Piceance Basins, the COGCC has consistently found that biogenic gas contains only methane and a very small amount of ethane, while thermogenic gas contains not just methane and ethane but also heavier hydrocarbons such as propane, butane, pentane, and hexanes.
As explained below, *Gasland* incorrectly attributes several cases of water well contamination in Colorado to oil and gas development when our investigations determined that the wells in question contained biogenic methane that is not attributable to such development.

The Weld County Wells

Gasland features three Weld County landowners, Mike Markham, Renee McClure, and Aimee Ellsworth, whose water wells were allegedly contaminated by oil and gas development. The COGCC investigated complaints from all three landowners in 2008 and 2009, and we issued written reports summarizing our findings on each. We concluded that Aimee Ellsworth's well contained a mixture of biogenic and thermogenic methane that was in part attributable to oil and gas development, and Mrs. Ellsworth and an operator reached a settlement in that case.

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However, using the same investigative techniques, we concluded that Mike Markham's and Renee McClure's wells contained biogenic gas that was not related to oil and gas activity. Unfortunately, *Gasland* does not mention our McClure finding and dismisses our Markham finding out of hand.

The Markham and McClure water wells are both located in the Denver-Julesburg Basin in Weld County. They and other water wells in this area draw water from the Laramie-Fox Hills Aquifer, which is composed of interbedded sandstones, shales, and coals. Indeed, the water well completion report for Mr. Markham's well shows that it penetrated at least four different coal beds. The occurrence of methane in the coals of the Laramie Formation has been well documented in numerous publications by the Colorado Geological Survey, the United States Geological Survey, and the Rocky Mountain Association of Geologists dating back more than 30 years. For example, a 1976 publication by the Colorado Division of Water Resources states that the aquifer contains "troublesome amounts of . . . methane." A 1983 publication by the United States Geological Survey similarly states that "[m]ethane-rich gas commonly occurs in ground water in the Denver Basin, southern Weld County, Colorado." And a 2001 report by the Colorado Geological Survey discusses the methane potential of this formation and cites approximately 30 publications on this subject.

Laboratory analysis confirmed that the Markham and McClure wells contained biogenic methane typical of gas that is naturally found in the coals of the Laramie–Fox Hills Aquifer. This determination was based on a stable isotope analysis, which effectively "finger-printed" the gas as biogenic, as well as a gas composition analysis, which indicated that heavier hydrocarbons associated with thermogenic gas were absent. In addition, water samples from the wells were analyzed for benzene, toluene, ethylbenzene, and xylenes (BTEX), which are constituents of the hydrocarbons produced by oil and gas wells in the area. The absence of any BTEX compounds in these water samples provided additional evidence that oil and gas activity did not contaminate the Markham and McClure wells.

The COGCC has also reviewed the records for all oil and gas wells located within one-half mile of the Markham and McClure wells, which is more than double the typical hydraulic fracture length in Colorado. This review indicated that: all oil and gas wells near the Markham well were drilled and hydraulically fractured in 1991, except for two wells that were fractured in 2005 and 2006, respectively; and all oil and gas wells near the McClure well were drilled and hydraulically fractured in 2002, except for one well that was hydraulically fractured in 2005. The records do not reflect any pressure failures or other problems associated with these wells that would indicate a loss of fracture fluid or gas from the well bore into the surrounding geologic formations.

In support of its thesis that the Markham and McClure water wells were contaminated by oil and gas development, the *Gasland* website makes several arguments that merit a brief response. First, the website quotes Professor Anthony Ingraffea of Cornell University for the proposition that drilling and hydraulic fracturing could cause biogenic methane to migrate into aquifers under certain circumstances. However, Professor Ingraffea's statement does not suggest that these circumstances apply to the Markham and McClure wells, nor does it address the extensive scientific literature establishing that biogenic methane is naturally present in the aquifer in question. Second, the website quotes Weston Wilson, an Environmental Protection Agency employee, speculating that oil and gas operators in Weld County are withdrawing large amounts of groundwater and that these withdrawals are releasing biogenic methane. However, oil and gas companies in Weld County obtain most of their water from municipalities, which obtain such water from surface water sources such as the Colorado-Big Thompson and Windy

Gap projects. Finally, the website asserts that the water in the Markham and McClure wells deteriorated after drilling and hydraulic fracturing occurred nearby. However, COGCC records indicate little or no temporal relationship between the Markham and McClure complaints and nearby drilling and hydraulic fracturing activities, which occurred several years earlier and in most cases many years earlier.

The West Divide Creek Seeps

Gasland also addresses complaints about oil and gas activity in the West Divide Creek area of the Piceance Basin in Garfield County, though it again confuses issues related to biogenic gas with those related to thermogenic gas. The film focuses on two seeps that are in close geographic proximity but derive from different origins. One of the seeps occurs in a wetland on property owned by Lisa Bracken, who appears in the film; it contains biogenic methane. The other seep, which the COGCC terms the West Divide Creek gas seep, is about 1,500 feet to the south on property owned by a neighbor; it contains thermogenic methane caused by EnCana's failure to properly cement a natural gas well.

Gasland adopts the claim that the West Divide Creek gas seep was caused by hydraulic fracturing. After investigating the matter thoroughly in 2004, COGCC staff concluded the seep was caused by gas migrating up a gas well borehole that had not been properly cemented and in which the upper portion of the gas bearing Williams Fork Formation had not been isolated. On August 16, 2004, following a public hearing, the COGCC commissioners approved an enforcement order (Order 1V-276) that incorporated the staff's causation conclusions and assessed a substantial fine against the operator.

In investigating the West Divide gas seep, the COGCC determined that it contains thermogenic methane. The gas composition and stable isotope signature of the gas closely matched that of the gas being produced from the Williams Fork Formation. The gas from both the West Divide Creek seep and the Williams Fork Formation is composed primarily of methane, but it also contains ethane, propane, butane, pentane, and hexanes. In addition, BTEX compounds were detected in ground and surface water in the vicinity of the West Divide Creek seep, which indicates that the gas is related to oil and gas activities and not of biogenic origin.

In contrast, the laboratory results for the gas samples collected from the seep on Ms. Bracken's property have demonstrated that the gas is biogenic. The COGCC has collected nine gas samples on six different occasions during 2004, 2007, 2009, and 2010. With respect to each sample, the gas composition was found to be 100 percent methane, no heavier hydrocarbon compound was detected, and the stable isotope ratio indicated that the gas is biogenic. The COGCC has also collected six water samples on four different occasions during 2004, 2007, and 2009 and ten soil samples on multiple occasions during 2008 and 2009 from Ms. Bracken's property. BTEX compounds and/or other hydrocarbons associated with oil and gas operations were not detected in any of these samples. Based on these results, the COGCC has concluded that the gas seep on Ms. Bracken's property resulted from the fermentation of organic matter by methanogenic bacteria. This is not uncommon in wetland areas, such as those that exist along West Divide Creek.

Other Information

Oil and gas development is an industrial activity, and property owners sometimes complain that it has contaminated their water well. The COGCC investigates all such complaints and reports the results individually to the complainant and collectively to the Colorado Water Quality Control

Division. In some cases, the COGCC has found that the well contains thermogenic methane linked to oil and gas development. In most cases, however, the COGCC has found that contamination is not present or that the methane comes from biogenic sources and is not attributable to oil and gas production. The following excerpt from a report summarizing the COGCC's investigation following the contamination of the Ellsworth water well is illustrative:

> In response to concerns regarding the presence of methane gas in water wells completed in the Laramie/Fox Hills Aquifer, COGCC, Noble Energy, and Anadarko/Kerr McGee sampled a total of 28 water wells between March 25, 2009 and April 7, 2009 across an approximately 170 square mile area. Sample results show that these wells contained either no methane gas or biogenic (biological generated) methane gas. None of these wells, other than the Ellsworth water well, contained thermogenic methane gas. The sample results along with letters discussing the results were sent by COGCC staff to the 28 well owners [who had requested testing].

Nevertheless, it remains important to establish prudent regulations to ensure that other resources, such as groundwater, are protected. Producing oil and gas formations in much of Colorado, including the Denver-Julesburg and Piceance Basins, lie at depths of up to 8,000 feet below the ground surface, while the aquifers that sustain domestic water wells are generally less than 1,000 feet below the ground surface. COGCC regulations establish casing and cementing standards to ensure that gas being produced from 8,000 feet down does not leak into the shallower aquifers. These regulations require wells to be cased with steel pipe and the casing to be surrounded by cement to create a hydraulic seal within the annular space between the wall of the well bore and the steel pipe. In addition, a number of recent amendments to the COGCC regulations address concerns raised about hydraulic fracturing:

- Rule 205 requires operators to inventory chemicals, including fracturing fluids, and to provide this information upon request to the COGCC and certain health care professionals;
- Rule 317 requires cement bond logs to confirm that aquifers are protected;
- Rule 317B imposes mandatory setbacks and enhanced environmental precautions on oil and gas development occurring near public drinking water sources;
- Rule 341 requires well pressures to be monitored during hydraulic fracturing;
- Rule 608 mandates additional pressure testing and water well sampling for coalbed methane wells; and
- Rules 903 , 904 , and 906 impose enhanced requirements for pit permitting, lining, monitoring, and secondary containment to ensure that pit fluids, including hydraulic fracturing flowback, do not leak.

Finally, it should be understood that the COGCC Director, Dave Neslin, offered to speak with *Gasland's* producer, Josh Fox, on camera during the filming of the movie. Because the issues are technical and complex and arouse concerns in many people, Director Neslin asked that he be allowed to review any material from the interview that would be included in the final film. Unfortunately, Mr. Fox declined. Such a discussion might have prevented the inaccuracies noted above.

Alaska Oil and Gas Conservation Commission

Hydraulic Fracturing in Alaska

The AOGCC's statutes and regulations, found in Chapter 5 of Title 31 of the Alaska Statues and Title 20, Chapter 25 of Alaska's Administrative Code, apply to all oil, gas, and geothermal wells drilled in the state. These statutes and regulations include stringent well construction requirements that are designed to protect underground sources of water and ensure mechanical integrity during production and injection operations. The AOGCC has no specific regulations governing hydraulic fracturing for conventional oil, gas, and geothermal development. However the AOGCC is required by statute to take extra measures to protect underground sources of drinking water in "nonconventional gas" operations, including hydraulic fracturing operations. Non-conventional gas includes coal bed methane and shale gas, both of which usually require production and disposal of significant amounts of water to establish and maintain gas flow.

The AOGCC does not have any rules regarding disclosure of hydraulic fracturing fluids. Proposed fracturing programs are described in the application for permit to drill a new well (Form 10-401) or in an Application for Sundry Approvals (Form 10-403) when such work is planned on an existing well. Disclosure of the chemical composition or the anticipated volume of fluid is not currently required for either permit. However, Material Safety Data Sheets are required by federal law to be available on location. For hydraulic fracturing operations, these sheets list every chemical used in the fracturing process and must be disclosed to the AOGCC if requested. In instances where fracturing is proposed in a drilling permit application, volumes may or may not be included because completion interval thickness, permeability and other characteristics that determine required fluid volumes generally are not known before the well is drilled. The volume of fluid actually used must be disclosed in the final completion report for each fractured well.

On the North Slope, Alaska's most prolific oil and gas province, freshwater is not a concern. In this part of Alaska, a thick layer of soil is underlain by permafrost – ground that remains frozen year round – so there is no liquid water, other than surface water, to a depth of 1000 to 2000 feet. Below the permafrost, only salt water is present, with very few exceptions. Regardless, wells on the North Slope are held to the same stringent construction requirements as other wells throughout the State.

Wherever underground sources of drinking water are present, they are protected by Commission regulations. All operators are required to obtain advance approval for well work, including drilling. Mechanical integrity requirements are the primary means for protecting drinking water. In order to operate, all wells must demonstrate competent barriers to prevent the flow of any fluids from the well to the surrounding rocks. These barriers are supplied by strings of pipe in the wells as well as cement and mechanical devices that pack-off (i.e., seal) the pipe. Every well must have a surface casing that is set below the base of the deepest formation that could potentially be a source of drinking water. That casing must be cemented completely to the surface. As a well is drilled deeper, every additional casing string must also be cemented sufficiently to restrict fluids to their native reservoirs. Wells which cannot demonstrate competent barriers are required to be shut-in immediately.

To assure compliance, every operator is required to install pressure measurement devices on every well and monitor those devices daily. If a measurement device indicates a compromise of the well's mechanical integrity, the operator is required to shut-in the well immediately and notify the Commission. In addition to these monitoring devices, the Commission requires periodic mechanical integrity tests on all wells. The AOGCC has a total of five field inspectors who randomly witness the tests as they are performed. Regardless of whether or not an inspector is present for a pressure test, the operators are required to submit to the AOGCC documentation for every test conducted. All test information is reviewed thoroughly by AOGCC engineers. Unannounced inspections also assure regulatory compliance.

In over fifty years of oil and gas production, Alaska has yet to suffer a single documented instance of subsurface damage to an underground source of drinking water. As long as each well is properly constructed and its mechanical integrity is maintained, hydraulic fracturing should have no potential to damage any fresh groundwater.

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RESOLUTION 10.052

Urging the Congressional Conference Committee on Bill H.R. 2996 and the Environmental Protection Agency to Remain Within the Scope of the Directive to EPA

WHEREAS, the United States Congress charged the EPA "*to carry out a study on the relationship between hydraulic fracturing and drinking water, using a credible approach that relies on the best available science, as well as independent sources of information. The conferees expect the study to be conducted through a transparent, peer-reviewed process that will ensure the validity and accuracy of the data. The Agency shall consult with other Federal agencies as well as appropriate State and interstate regulatory agencies in carrying out the study, which should be prepared in accordance with the Agency's quality assurance principles;*" and,

WHEREAS, comments to the EPA Science Advisory Board from many parties urged EPA to not unnecessarily and unreasonably expand the scope of the study; and,

WHEREAS, the United States Congress, in the Energy Policy Act of 2005, clarified that the Safe Drinking Water Act (SDWA) does not cover hydraulic fracturing; and,

WHEREAS, the Interstate Oil and Gas Compact Commission (IOGCC) conducted a survey of oil and gas producing states and found no cases of ground water contamination associated with hydraulic fracturing; and,

WHEREAS, the member states of the IOGCC have adopted comprehensive laws and regulations to provide for safe operations and to protect the nation's drinking water sources, and maintain staffs of well trained personnel to effectively regulate oil and gas exploration and production and to insure compliance; and,

WHEREAS, hydraulic fracturing is currently, and has been for decades, a common well completion technique allowed by state rules and regulations and used in hydrocarbon production by the oil and gas industry in the 30 member states of the IOGCC without detrimental impact to ground water; and,

WHEREAS, approximately 35,000 wells are hydraulically fractured annually in the United States and close to one million wells have been hydraulically fractured in the United States since the technique's inception, with no known harm to ground water; and,

WHEREAS, the regulation of oil and gas exploration and production activities, including hydraulic fracturing, is a power and responsibility of the various states; and,

WHEREAS, the SDWA does not grant to the federal government authority to regulate oil and gas drilling and production operations, such as hydraulic fracturing, under the Underground Injection Control program; and,

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WHEREAS, production of coal seam natural gas, natural gas from shale formations and natural gas from low permeability reservoirs is increasingly important to domestic natural gas supply and will be even more important in the future to reduce this nation's dependence on unreliable energy sources and to increase our national security; and,

WHEREAS, hydraulic fracturing plays a major role in the development of virtually all unconventional oil and gas resources and, thus, should not be limited in the absence of any evidence that such fracturing impacts underground sources of drinking water;

NOW, THEREFORE, BE IT RESOLVED, the IOGCC hereby declares its support for the study as defined by the Congressional Conference Committee on Bill H.R. 2996 directive to EPA;

BE IT FURTHER RESOLVED, that the IOGCC urges the EPA to specifically seek the advice and close participation of the states, expressly the oil and gas regulatory agencies, in the design and execution of this study.

History:	Submitted by Lynn Helms, Official Representative, North Dakota, April 20, 2010 Approved by Business Committee, May 25, 2010, Lexington, Kentucky